INEOS Olefins & Polymers USA

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Certified Mail
70081830000244435751

August 6, 2013
DRL 00613

Mr. Jeff Robinson
Chief, Air Permit Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Re: Application for PSD Air Quality Permit Greenhouse Gas Emissions
Ethylene Oxide/Ehtylene Glycol Plant
INEOS USA LLC
La Porte, Harris County, Texas
RN 100229905, CN 602817884

Dear Mr. Robinson:

INEOS USA LLC (INEOS) submits the enclosed application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions in support of a proposed Ethylene Oxide/Ethylene Glycol Plant to be constructed at INEOS's Battleground Manufacturing Complex in La Porte, Harris County.

A State NSR and PSD permit application for other regulated pollutants has been submitted to TCEQ. INEOS is committed to working with EPA to ensure a timely review of our permit application. Representatives of INEOS and its consultant, RPS, are available to meet with your team at your convenience in your offices to discuss the project and answer any questions you may have. Biological Assessment and Cultural Resources evaluation are currently underway, and reports presenting these analyses will be submitted under separate cover when completed.

Should you have questions concerning this application, or require further information, please do not hesitate to contact Mr. Dan Lutz, Environmental Advisor, at (713) 373-9300

Sincerely,

Robert J Bradshaw

Robert Bradshaw

Site Manager

Enclosure

Cc: Ms. Melanie Magee, US EPA Region 6, 1445 Ross Avenue, Suite 1200, Dallas, TX 75202
(Cover Letter w/o attachments) **(Certified Mail 70081830000244435768)**

Mr. Steve Langevin, RPS, 411 North Sam Houston Parkway East, Suite 400, Houston, TX 77060
(Certified Mail 70081830000244435775)

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Application for Prevention of Significant Deterioration Air Permit Greenhouse Gas Emissions

Ethylene Oxide/Ethylene Glycol Plant
La Porte, Texas

Submitted by
INEOS USA LLC

August 2013

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Section 1
Introduction

INEOS USA LLC (INEOS) currently operates the Battleground Manufacturing Complex (Complex) near La Porte in Harris County, TX. The Complex is north of the Pasadena Freeway (SH 225) and east of Independence Parkway. INEOS is planning to build a new ethylene oxide (EO)/ethylene glycol (EG) manufacturing plant and related facilities (the Project) at the Complex. The EO/EG plant will react ethylene and oxygen to make ethylene oxide. Ethylene oxide will be subsequently sold to customers or further reacted to form various ethylene glycols for sale. The Project will also include a cogeneration facility and a boiler facility to provide steam and power for the EO/EG plant unless those are sourced from off-site. Sources of Project GHG emissions include:

- CO_2 Stripper vent,
- Steam and electric power generation facilities,
- Process flare,
- Process fugitives,
- Diesel engines for emergency use, and
- Maintenance, startup, and shutdown (MSS) activities.

A federal New Source Review permit amendment application has been submitted to TCEQ for this Project. The Project triggers NNSR for NO_x and PSD review for NO_x, CO, and $PM/PM_{10}/PM_{2.5}$, for which TCEQ has approved permitting programs. The Project also triggers PSD review for greenhouse gas (GHG) emissions. EPA has issued a FIP authorizing EPA's PSD permitting of GHG emissions in Texas pending implementation of an approved permitting program by TCEQ. The purpose of this permit application is to obtain a PSD permit for the GHG emissions associated with the Project.

This document constitutes the required PSD permit application for the GHG emissions from the Project. Because EPA has not developed application forms for GHG permitting, TCEQ forms are used where deemed appropriate. The application is organized as follows:

- **<u>Section 1:</u>** Identifies the project for which authorization is requested and presents the application document organization.

- **<u>Section 2:</u>** contains administrative information and completed TCEQ federal NSR applicability Tables 1F, 2F, and 3F for GHG emissions.

- **Section 3:** Contains the area map showing the facility location and the plot plan showing the location of each emission points with respect to the plant property.
- **Section 4:** Contains a brief process description and simplified process flow diagrams.
- **Section 5:** describes the basis of the calculations for the Project GHG emissions increases and includes the proposed GHG emission limits.
- **Section 6:** includes an analysis of best available control technology for the new and modified sources of GHG emissions associated with the Project.
- **Appendix A:** Contains emissions calculations for the new and modified sources of GHG emissions associated with the Project.
- **Appendix B:** Contains summaries of the RBLC database searches.

Section 2
TCEQ Forms and Application Fee

This section contains the following forms:

- Administrative Information
- TCEQ Table 1F
- TCEQ Table 2F
- TCEQ Table 3F

Tables 1F, 2F and 3F are federal NSR applicability forms. Because this application covers only GHG emissions, and PSD permitting of other pollutants is being conducted by TCEQ, these forms only include GHG emissions. As shown in both the Table 1F and 2F, GHG emissions from the project exceed 75,000 tpy of CO_2e; therefore, a Table 3F, which includes the required netting analysis, is also included. The net increase in GHG emissions exceeds 75,000 tpy of CO_2e; therefore, PSD review is required.

Administrative Information

A. Company or Other Legal Name: INEOS USA LLC		
B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Mr. Robert Bradshaw		
Title: Site Manager		
Mailing Address: 1230 Independence Parkway		
City: La Porte	State: TX	ZIP Code: 77571
Telephone No.: 713-307-3437	Fax No.:	E-mail Address: robert.bradshaw@ineos.com
C. Technical Contact Name: Mr. Daniel Lutz		
Title: Environmental Advisor		
Company Name: INEOS USA LLC		
Mailing Address: 1230 Independence Parkway		
City: La Porte	State: TX	ZIP Code: 77571
Telephone No.: 713-373-9300	Fax No.:	E-mail Address: daniel.lutz@ineos.com
D. Facility Location Information:		
Street Address: 1230 Independence Parkway		
If no street address, provide clear driving directions to the site in writing:		
City: La Porte	County: Harris	ZIP Code: 77571
E. TCEQ Account Identification Number (leave blank if new site or facility):		
F. TCEQ Customer Reference Number *(leave blank if unknown)*: CN602817884		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN100229905		
H. Site Name: INEOS Battleground Manufacturing Complex		
I. Area Name/Type of Facility: Ethylene Oxide/Ethylene Glycol Plant		☒ Permanent ☐ Portable
J. Principal Company Product or Business: : Ethylene Oxide/Ethylene Glycol		
K. Principal Standard Industrial Classification Code: 2869		
L. Projected Start of Construction Date: 06/01/2014	Projected Start of Operation Date: 01/01/2016	
SIGNATURE		
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief.		
NAME: Mr. Robert Bradshaw, Site Manager		
SIGNATURE: Robert J Bradshaw *Original Signature Required*		
DATE: August 8, 2013		

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	**TBD**	Application Submittal Date:	**August 2013**
Company:	**INEOS USA LLC**		
RN:	**100229905**	Facility Location: **1230 Independence Parkway**	
City:	**La Porte**	County: **Harris**	
Permit Unit I.D.:	**Ethylene Oxide/Ethylene Glycol Plant**	Permit Name: **Ethylene Oxide/Ethylene Glycol Plant**	
Permit Activity: New Source ___ Modification **X**			
Project or Process Description: **Construction of Ethylene Oxide/Ethylene Glycol Unit**			

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS								
	Ozone		CO	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	Other[1]
	VOC	NO_x							GHG*
Nonattainment? (yes or no)	Yes	Yes	No	No	No	No	No	No	NA
Existing site PTE (tpy)?	>100	>100	>250				>250		>100,000
Proposed project emission increases (tpy from 2F)[2]	24.76	55.6	170.1	37.9	35.6	33.6	55.6	8.5	624,180
Is the existing site a major source? [3]If not, is the project a major source by itself?	NA	NA	NA	NA	NA	NA	NA	NA	Yes
Significance Level (tpy)	5	5	100	25	15	10	40	40	75,000
If site is major, is project increase significant?	NA	Yes	Yes	Yes	Yes	Yes	Yes	NA	Yes
If netting required, estimated start of construction?	1-Jun-14								
Five years prior to start of construction	1-Jun-09								
Estimated start of operation	1-Jun-16								
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	-0.24	78.6	253.7	42.0	39.2	36.3	78.6	NA	681,707
FNSR APPLICABLE? (yes or no)	No	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes

*** GHG emissions expressed as CO_2e**

1 Other PSD pollutants.

2 Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).

3 Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).

The representations made above and on the accompanying tables are true and correct to the best of my knowl

[signature] — Site Manager

Signature — Title

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	**GHG (expressed as CO_2e)**	**Permit No.:**	**TBD**
Baseline Period:	**NA**	**Project Name:**	**Ethylene Oxide/Ethylene Glycol Plant**

	Affected or Modified Facilities[2]			Permit No.	Actual Emissions[3] (tons/yr)	A Baseline Emissions[4] (tons/yr)	B Proposed Emissions[5] (tons/yr)	Projected Actual Emissions (tons/yr)	Difference (B-A)[6] (tons/yr)	Correction[7] (tons/yr)	Project Increase[8] (tons/yr)
	FIN	EPN	Facility Name								
1	U-2650, U-2651, U-2652, U-2653	U-2650, U-2651, U-2652, U-2653	Cogeneration Unit/Boiler Cap	TBD		-	389,094		389,094	-	389,094
2	MP-2840A	MP-2840A	FIREWATER PUMP DIESEL DRIVER	TBD		-	21.6		21.65	-	21.65
3	MP-2840B	MP-2840B	FIREWATER PUMP DIESEL DRIVER	TBD		-	21.6		21.65	-	21.65
4	EGEN-1	EGEN-1	EMERGENCY GENERATOR	TBD		-	68.9		68.9	-	68.9
5	V-5002	C-6961	CO2 Stripper Vent CatOx Unit	TBD		-	233,597		233,597	-	233,597
6	V-5002	B-6961	CO2 Stripper Vent CatOx Unit Bypass								
7	U-2640	U-2640	FLARE - ROUTINE OPERATIONS	TBD		-	1051.4		1,051.4	-	1,051.4
8	MSS-C	MSS-C	MAINTENANCE STARTUP AND SHUTDOWN - CONTROLLED	TBD		-	226.8		226.8	-	226.8
9	MSS-U	MSS-U	MAINTENANCE STARTUP AND SHUTDOWN - UNCONTROLLED	TBD		-	0.9		0.9	-	0.9
10	FUG-1	FUG-1	EO/EG PLANT EQUIPMENT LEAK FUGITIVES	TBD		-	13.3		13.3	-	13.3
11	FUG-2	FUG-2	STEAM PLANT EQUIPMENT LEAK FUGITIVES	TBD		-	84.8		84.8	-	84.8
										Page Subtotal[9]:	**624,180**
										Project Total:	**624,180**

Table 3F
Project Contemporaneous Changes

Company: **INEOS USA LLC**

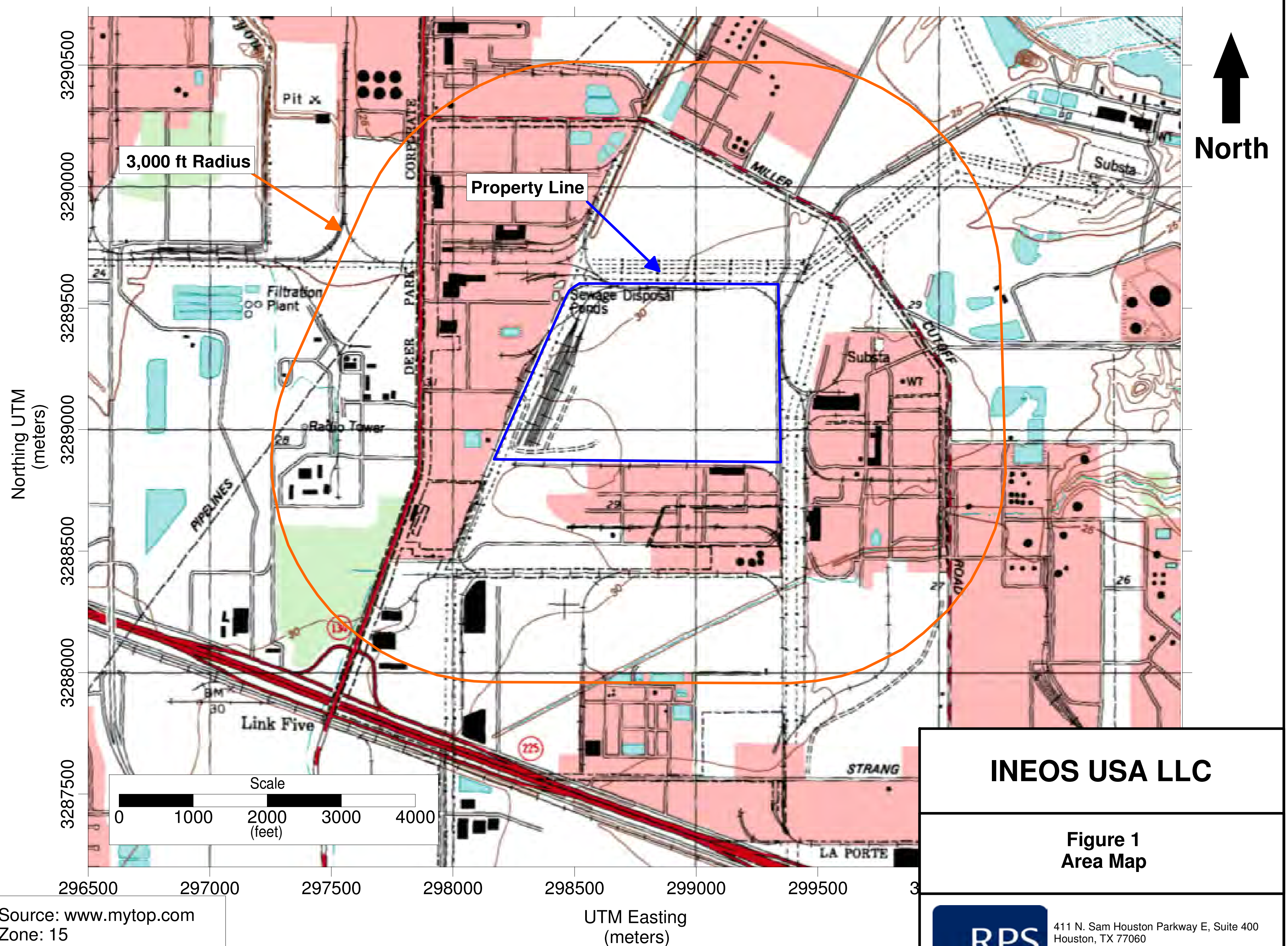
Criteria Pollutant: **GHG (as CO_2e)**

Permit Application No. **TBD**

No.	PROJECT DATE	EMISSION UNIT AT WHICH REDUCTION OCCURED FIN	EPN	PERMIT NUMBER	PROJECT NAME OR ACTIVITY	A PROPOSED EMISSIONS (tons / year)	B BASELINE EMISSIONS (tons / year)	C DIFFERENCE (A-B) (tons / year)	CREDITABLE DECREASE OR INCREASE (tons / year)
1	9/1/2015	PE-HRSG21	PE-HRSG21	106824	Cogen Unit 1	29,147	0	29,147	29,147
2	9/1/2015	PE-HRSG22	PE-HRSG22	106824	Cogen Unit 2				
3	9/1/2015	PE-HRSG23	PE-HRSG23	106824	Cogen Unit 3				
4	9/1/2015	PE-HRSG24	PE-HRSG24	106824	Cogen Unit 4				
5	9/1/2015	PE-FLARE2	PE-FLARE2	28351	Flare - PE	28,380	0	28,380	28,380
6	6/1/2016	U-2650, U-2651, U-2652, U-2653	U-2650, U-2651, U-2652, U-2653	TBD	Cogeneration Unit/Boiler Cap	389,094	0	389,094	389,094
7	6/1/2016	MP-2840A	MP-2840A	TBD	FIREWATER PUMP DIESEL DRIVER	22	0.00	22	22
8	6/1/2016	MP-2840B	MP-2840B	TBD	FIREWATER PUMP DIESEL DRIVER	22	0.00	22	22
9	6/1/2016	EGEN-1	EGEN-1	TBD	EMERGENCY GENERATOR	69	0.00	69	69
10	6/1/2016	V-5002	C-6961	TBD	CO2 Stripper Vent CatOx Unit	233,597	0.00	233,597	233,597
11	6/1/2016	V-5002	B-6961	TBD	CO2 Stripper Vent CatOx Unit Bypass				
12	6/1/2016	U-2640	U-2640	TBD	FLARE - ROUTINE OPERATIONS	1,051	0.00	1,051	1,051
13	6/1/2016	MSS-C	MSS-C	TBD	MAINTENANCE STARTUP AND SHUTDOWN - CONTROLLED	226.76	0.00	226.76	226.76
14	6/1/2016	MSS-U	MSS-U	TBD	MAINTENANCE STARTUP AND SHUTDOWN - UNCONTROLLED	0.91	0.00	0.91	0.91
15	6/1/2016	FUG-1	FUG-1	TBD	EO/EG PLANT EQUIPMENT LEAK FUGITIVES	13	0.00	13	13
16	6/1/2016	FUG-2	FUG-2	TBD	STEAM PLANT EQUIPMENT LEAK FUGITIVES	85	0.00	85	85
								PAGE SUBTOTAL:	**681,707**
Summary of Contemporaneous Changes								TOTAL :	**681,707**

Section 3
Area Map and Plot Plan

An Area Map showing the location of the Battleground Manufacturing Complex and the location of the EO/EG plant at the Complex is presented in Figure 3-1. A plot plan of the EO/EG plant and related facilities is presented in Figure 3-2.

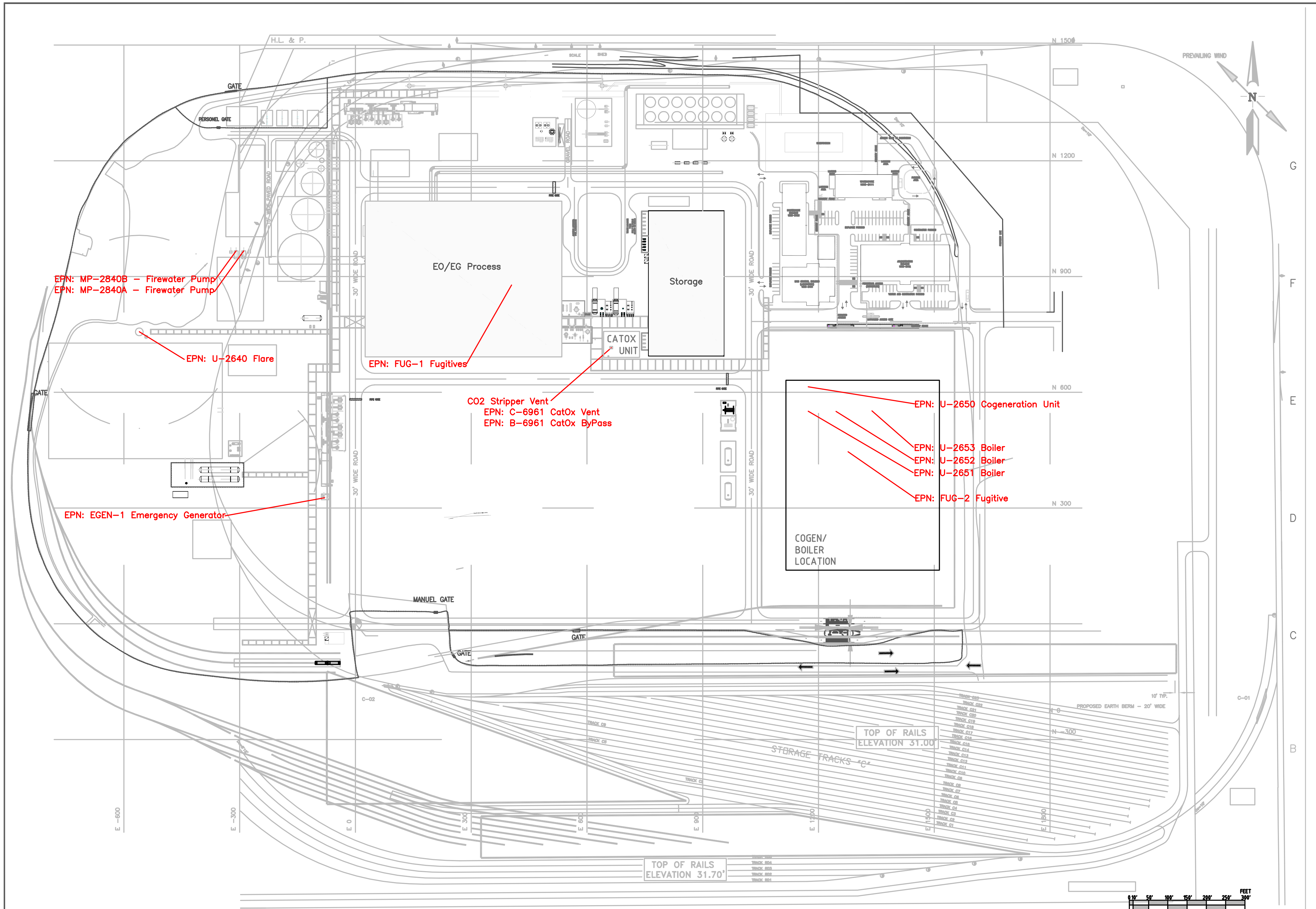


Source: www.mytop.com
Zone: 15
Coordinate Datum: NAD 83

INEOS USA LLC

Figure 1
Area Map

RPS
411 N. Sam Houston Parkway E, Suite 400
Houston, TX 77060



NOTES

INEOS USA LLC

FLUOR

FIGURE 3-2
EO/EG PLOT PLAN

RPS

411 N. Sam Houston Parkway E, Suite 400
Houston, TX 77060

NO.	REVISION	BY	DATE	CHK'D	APR'D	APR'D	DWG. NO.	REFERENCE DWG SUBJECT
A	ISSUED FOR BASIS OF ESTIMATE	PD	02-25-13	DS	FP			

11 10 9 8 7 6 5 4 3 2 1

G F E D C B A

Section 4
Process Description

A description of the proposed process is included in this section. Figure 4-1 is a simplified process flow diagram of the overall process. Figure 4-2 is a process flow diagram for the Cogeneration facility, and Figure 4-3 is a process flow diagram for the Boiler facility.

4.1 Overview

INEOS is planning to build a new ethylene oxide/ethylene glycol (EO/EG) plant near the city of La Porte in Harris County, Texas. This plant will combine ethylene and oxygen to produce ethylene oxide. The EO will either be sold as a product or further reacted to produce various ethylene glycols for sale. The sale of ethylene oxide and glycols will vary in response to marketplace and customer demands. Therefore, actual production rates will vary.

Major sections of the EO/EG process at the proposed facility include:

- EO Reaction;
- EO Recovery and Purification;
- Purge Glycol Unit;
- Glycol Reaction and Refining;
- Carbon Dioxide (CO_2) Stripping;
- EO and EG Product Loading;
- Steam and Electricity Production; and
- Routine maintenance, startup, and shutdown activities.

INEOS is submitting this GHG PSD preconstruction permit application to authorize the construction of the EO/EG plant and other associated activities as described above. Each part of the chemical manufacturing process and associated emissions are identified in the following discussion of the EO/EG process.

4.2 EO/EG Production Operations

4.2.1 EO Reaction

The EO Reaction Section will receive ethylene and oxygen raw materials by pipeline from external supplier(s). Ethylene and oxygen are reacted across a catalyst to produce ethylene oxide and by-product carbon dioxide (CO_2). The CO_2 by-product stream is sent to the CO_2 Stripping section of the plant.

4.2.2 EO Recovery and Purification

In the recovery process, EO from the Reaction Section is first absorbed into water. This water, rich in EO, is then stripped and reabsorbed in water. Part of the EO is further purified and send to pressurized EO storage tanks. The rest of the EO (absorbed in water) is used as feed for the glycol reaction section.

4.2.3 Purge Glycol Unit

The function of the Purge Glycol Unit is to recover glycol from the EO reaction and recovery section. After removal of water and impurities, ethylene glycol is partly recovered and routed to the Glycol Refining section of the plant. A polyglycol mixture remains as by-product and is sent to storage (D-6917).

4.2.4 Glycol Reaction and Refining

In the Glycol Reaction Section, EO reacts with excess amounts of water to produce Mono-Ethylene Glycol (MEG), Di-Ethylene Glycol (DEG), and limited quantities of heavier glycols. After the glycol reaction, excess water Is removed and glycols are concentrated.

The Glycol Refining section of the plant is intended to remove the remaining water and to produce product quality MEG and DEG. MEG is then cooled and transferred as product to storage. DEG is also cooled and transferred to product storage.

Heavier glycols may also be produced by reacting EO product and MEG make to produce tri-ethylene glycol (TEG) and tetra-ethylene glycol (TTEG) as products, which are then sent to Product Storage.

4.2.5 Carbon Dioxide Stripping

In the CO_2 Stripping Section, the CO_2 produced in the Reaction Section is absorbed in a lean carbonate solution. The carbonate solution then goes to the CO_2 Regenerator. In the CO_2 Regenerator, potassium bicarbonate is regenerated by steam stripping. CO_2 that is liberated during regeneration is vented to the atmosphere. The vent stream is routed through a catalytic oxidation unit for VOC control prior to being discharged to the atmosphere. When maintenance is required, the catalytic oxidation unit may need to be by-passed for relatively short periods of time. The CO_2 by-product stream from the EO/EG plant exits at low pressure and must be compressed prior to treatment in the catalytic oxidation unit. During periods when the CO_2 by-product compressor is shutdown for maintenance, the CO_2 by-product stream must be emitted upstream of the catalytic oxidation unit until the compressor is restarted. Bypass of the catalytic oxidation unit has no significant effect on GHG emissions as the CO_2 contains only ppm levels of VOC; therefore, to the extent quantifiable, CO_2 emissions are the same both upstream and downstream of the catalytic oxidation unit.

4.2.6 EO/EG Product Loading

EO Product will either be used in the on-site EG process or sold to customers. When sold to customers, the EO product will be loaded into railcars. EG products will be transported off-site via pipeline. Some heavy (Poly)glycol product may be stored in the (Poly)glycol storage tanks and loaded into tank trucks for transportation.

4.3 Steam and Electricity Production

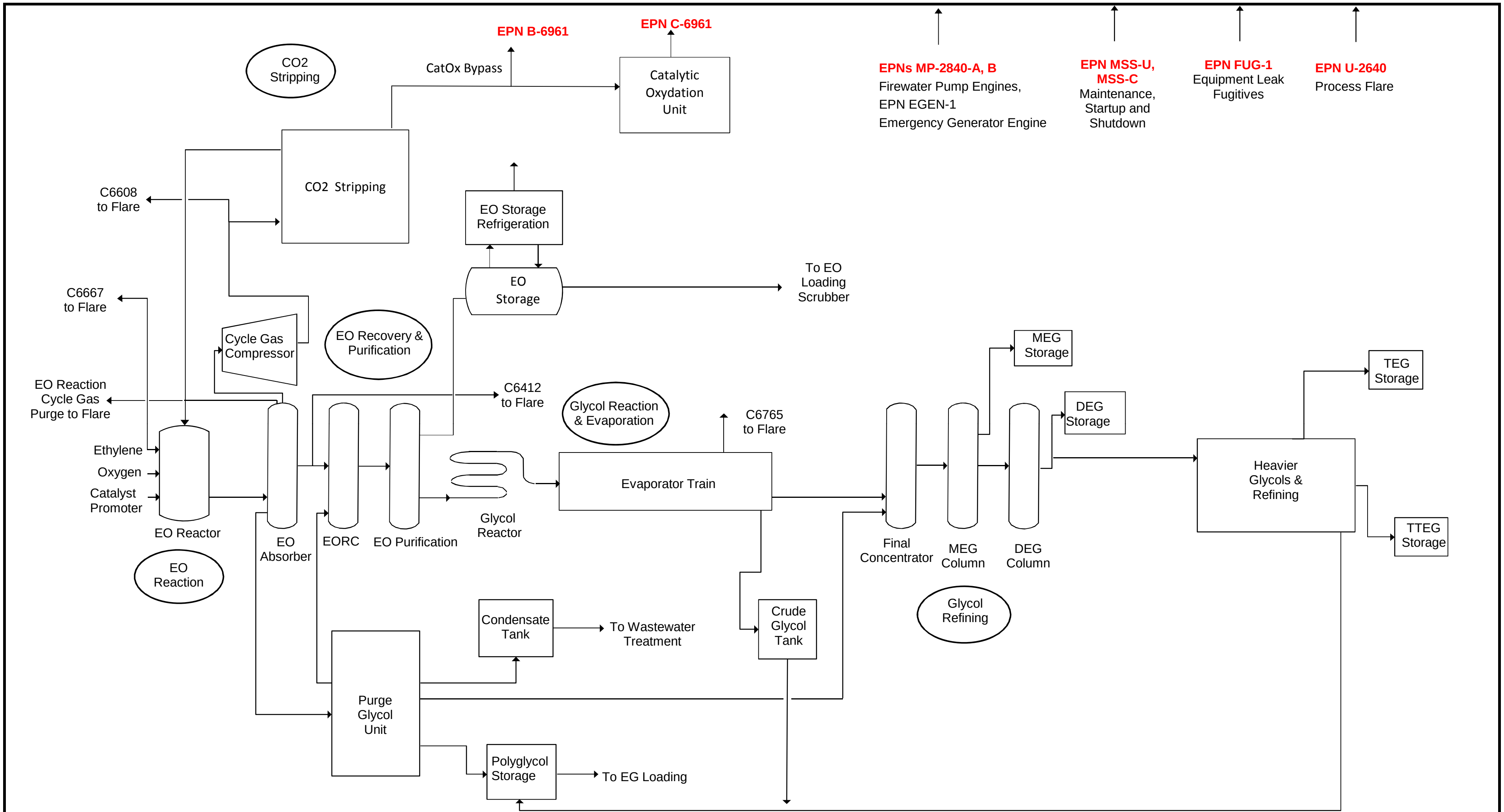
Steam and electricity required by the EO/EG plant will be provided by either a natural gas fired cogeneration facility (EPN U-2650) (Option 1), a natural gas fired boiler (EPN U-2651) (Option 2), or sourced from offsite. For both Options 1 and 2, two auxiliary/standby boilers (EPNs U-2652 and U-2653) will be included to provide steam when the primary facilities are out of service. The auxiliary/standby boilers will generally be operated at minimal capacity at all times to allow quick ramp up when needed to assure process safety.

These combustion units will also be used to control VOC emissions from process vents within the EO/EG plant. A summary of these process vents with estimated flow rates and vent stream composition is included in the emissions calculations in Appendix A. This vent stream data was obtained from proprietary process modeling from the EO/EG technology licensor.

This permit application does not include the offsite steam source option.

4.4 Routine Maintenance, Startup, and Shutdown Activities

Planned and predictable maintenance, startup, and shutdown (MSS) activities at the EO/EG plant will be conducted in a way that will minimize emissions to the atmosphere. This will generally be accomplished by clearing equipment before line openings or vessel opening. Where feasible, this equipment will be cleared back to the process to product storage or routed to the process flare. Additional details are found in Section 5.6 of this application. These MSS emissions are identified as EPN MSS.



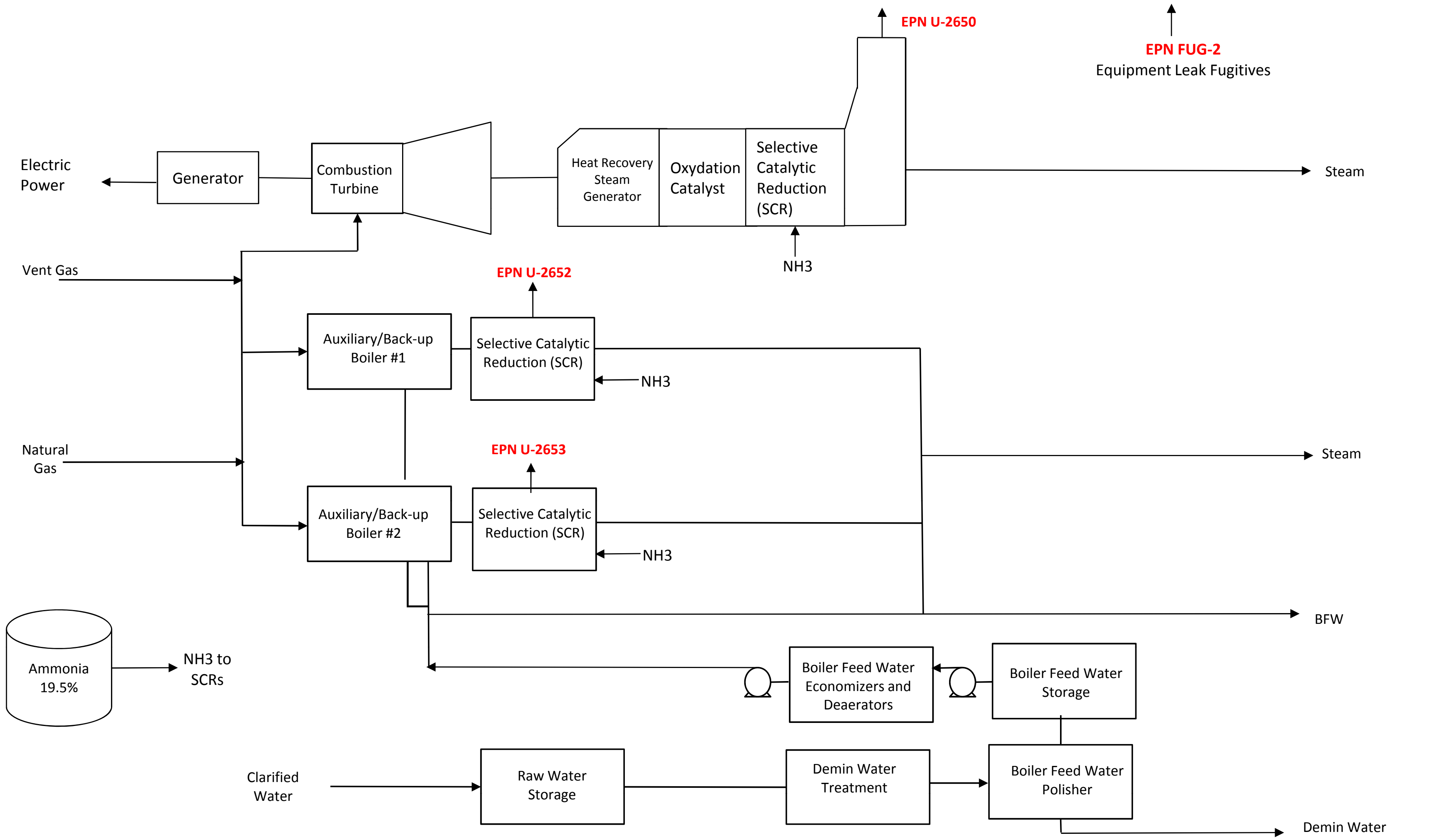
Note: Only EPNs that emit GHGs are identified on this diagram.

Ethylene Oxide/Ethylene Glycol Plant
La Porte , TX

Figure 4-1
Block Flow Diagram - EO/EG Process

RPS

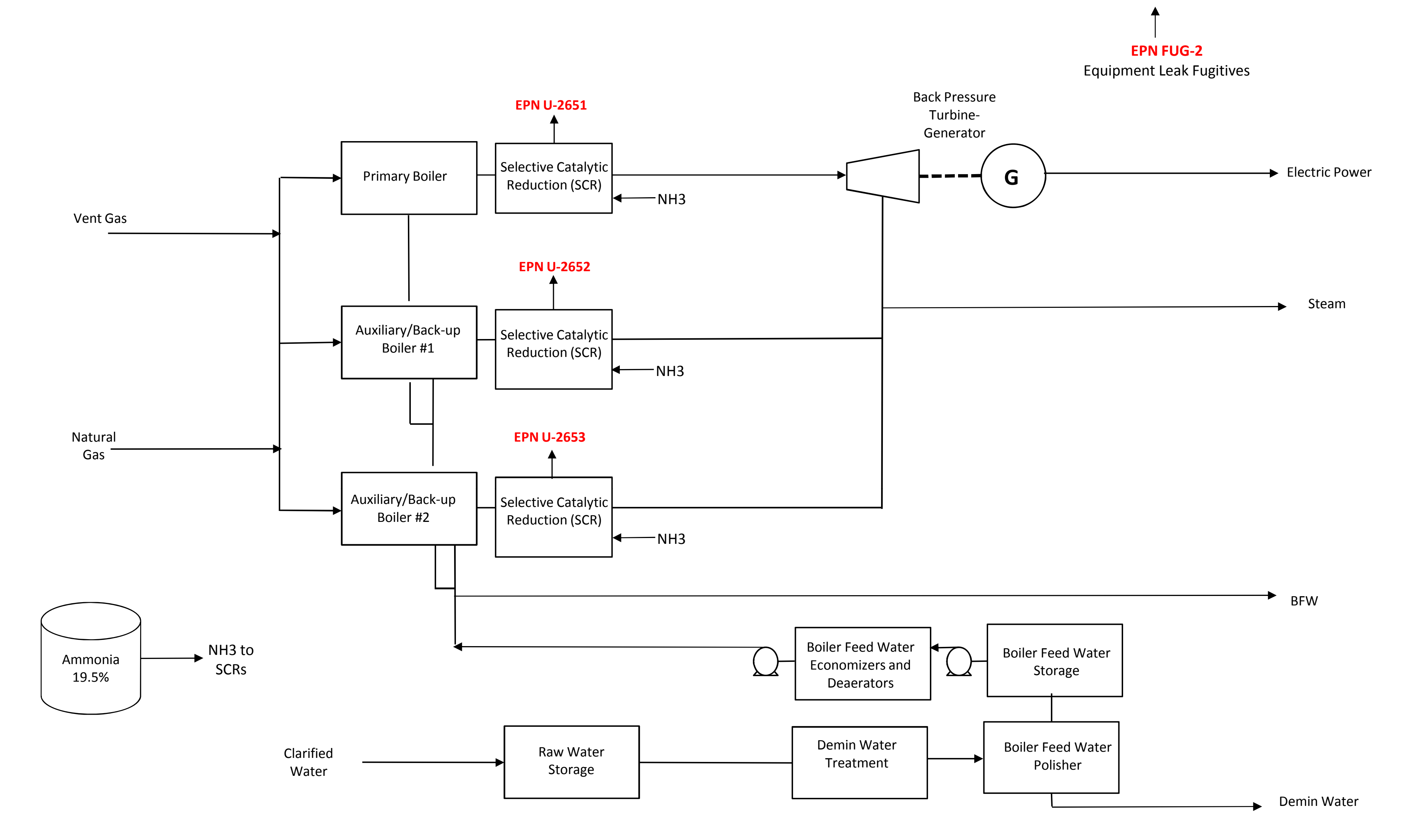
411 N. Sam Houston Parkway E. Suite 400,
Houston, Texas, 77060



Ethylene Oxide/Ethylene Glycol Plant
La Porte , TX

Figure 4-2
Block Flow Diagram -Cogeneration Facility

RPS
411 N. Sam Houston Parkway E. Suite 400,
Houston, Texas, 77060



Ethylene Oxide/Ethylene Glycol Plant
La Porte , TX

Figure 4-3
Block Flow Diagram - Boiler Facility

RPS

411 N. Sam Houston Parkway E. Suite 400,
Houston, Texas, 77060

Section 5
Emission Rate Basis

This section describes the bases of the GHG emissions calculations for new and modified sources of GHGs associated with the Project. Table 5-1 presents the proposed GHG emissions limits based on application of best available control technology proposed in Section 6 for each emission point or activity.

5.1 CO_2 Stripper Vent

A CO_2 by-product stream is produced in the Reaction Section of the EO/EG plant. CO_2 liberated from the CO_2 Stripping Section is expected to be 99+% CO_2 and will be exhausted to the atmosphere following control for VOC (EPN C-6971). For permitting purposes, it is assumed to be 100% CO_2; therefore, the emissions are calculated simply the average mass flow rate in lb/hr from plant design data converted to tons per year assuming 8,760 hour per year of operation. The CO_2 may contain trace amounts of VOC (<200 ppmv). To control the VOC emissions, the stream will be routed to a catalytic oxidation unit prior to being discharged to the atmosphere. The catalytic oxidation unit may be bypassed for short periods of time for maintenance purposes. Since the vent stream is 99+% CO_2, and VOC will average less than 200 ppmv, the effect of the catalytic oxidation unit on the stream is negligible (<0.02% variation). For this reason, the CO_2 emission rate is not dependent on the operation of the catalytic oxidation unit, and the 100% CO_2 concentration assumption is valid for all operating hours.

5.2 Steam and Electric Power Facilities

If steam and power are provided by an onsite source, one of two options will be pursued. Option 1 is a cogeneration facility (EPN U-2650) consisting of one turbine and a heat recovery steam generator (HRSG) with a duct burner. Option 2 is a boiler (EPN U-2651) combined with a steam turbine to produce electric power. For both options, two auxiliary boilers (EPNs U-2652 and U-2653) will be operated at all times at 10% of rated firing capacity to provide steam and power if the primary facility is out of service. With Option 2, the three boilers would be identical, with any one of the three being capable of operating as primary. For this reason, in addition to individual boiler emission limits, a total annual GHG emissions limit for all three boilers combined is proposed. The limit is based on the combined operating mode of three boilers: one at 100% of capacity and two at 10% of capacity at all times. To allow for operating flexibility, the emissions contribution from the standby boilers is based on each of the standby boilers operating at 10% of capacity 97.5% of the time and 100% capacity 2.5% of the time.

A combined emissions limit is also proposed for the cogeneration option. However, in this option, the cogeneration unit is always intended to be the primary operating unit, and the two standby boilers would by operated at 10% of capacity at all times during normal operation. The cogeneration unit at 100% of capacity emits less GHG emissions than a boiler at 100% of capacity, but the capability to operate with a boiler as the primary steam source is required in the event that the cogeneration unit is out of service for an extended period of time. As such, the combined emissions limit for the cogeneration option is based on the cogeneration unit at 100% capacity for 50% of the time, one boiler at 100% capacity for 50% of the time, and the second boiler at 10% capacity 100% of the time.

Compliance with the proposed limits would be determined based on a 12-month rolling average.

The primary fuel to be fired in the turbine, duct burner, and boilers is natural gas. Process vents will also be routed to these facilities for control. The hydrocarbon in the combined process vent streams will average about 98 wt% methane, with ethane and propane making up most of the remaining 2% of the hydrocarbon. These vent streams will provide about 25 mmBtu/hr (less than 5%) of the total heat input to the steam generating facilities. Because the combined composition of these vent streams is within the range of composition of natural gas, GHG emissions factors for natural gas are applicable to and were used to calculate the allowable emissions for both fuel sources for all facilities. CO_2 emissions were calculated based on the carbon content of the natural gas using Equation C-5 in 40 CFR Part 98, Subpart C. Emissions of CH_4 and N_2O were calculated from emission factors from Table C-2 of Appendix A to 40 CFR Part 98, Subpart C.

5.3 Process Flare

A flare (EPN U-2640) will be used to control routine vent streams that cannot be routed to the steam generating facilities for control and to control emissions from maintenance, startup, and shutdown events. These process streams contain hydrocarbons that when combusted by the flare produce CO_2 emissions. Natural gas used as assist gas to maintain the minimum heating value required for complete combustion also contains hydrocarbons, primarily methane, that also produce CO_2 emissions when burned. Any unburned methane from the flare will also be emitted to the atmosphere, and small quantities of N_2O emissions can result from the combustion process. Emissions of these pollutants were calculated based on the carbon content of the waste streams sent to the flare and of the natural gas used for assist with the same equations and emission factors from 40 CFR Part 98 that were used for the steam generating facilities (see Section 5.2). These equations and factors were applied to the maximum projected annual waste gas and natural gas flow rates to the flare.

5.4 Process Fugitives

Fugitive (equipment leak) emissions of methane will occur from the new process gas and natural gas piping components (EPNs FUG-1, FUG-2). The 28LAER leak detection and repair (LDAR) program will be applied to the new VOC components associated with the Project. In addition, all flanges and connectors will be monitored quarterly using the same leak detection level used for valves. All emissions calculations utilize current TCEQ factors and methods in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.* Each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). Uncontrolled emission rates were obtained by multiplying the number of fugitive components of a particular equipment/material type by the appropriate SOCMI emission factor. To obtain controlled fugitive emission rates, the uncontrolled rates were multiplied by a control factor, which was determined by the 28LAER LDAR program. The methane emissions were then calculated by multiplying the total controlled emission rate by the weight percent of methane in the natural gas and process gas.

5.5 Firewater Pump and Emergency Generator Engines

The firewater pump engines (EPNs MP-2840A and MP-2840B) and emergency generator engine (EPN EGEN-1) will be sources of combustion emissions. The engines will only operate during emergencies and on regularly scheduled intervals for testing. It is estimated that these engines will be operated a maximum of 52 hours per year each for testing. There will be no emissions from the engines during normal operation; therefore, annual emissions were based on 52 hours per year of operation. GHG emissions were calculated from emission factors for No. 2 distillate fuel in Tables C-1 and C-2 of Appendix A to 40 CFR Part 98, Subpart C.

5.6 Maintenance, Startup and Shutdown Emissions

Due to process controls and low vapor pressure of ethylene glycols, emissions from planned and predictable maintenance activities will be minimal. Plant shutdown will likely occur every year for replacement of the catalyst in the EO reactor. During MSS events, equipment will be cleared of all gas or liquids by returning to the process and de-pressured to the flare as feasible, and then opened to the atmosphere. The GHG emissions calculations from MSS flaring are described in Section 5.3. Methane is a component of the process fluids contained in the equipment that is cleared prior to maintenance. This methane is part of the residual gas that is released to the atmosphere after depressuring to the flare. The methane emissions from these releases are calculated by multiplying the wt% of methane by the total mass of the gas released.

CO_2 emissions are essentially unchanged during startup and shutdown as any minor combustion efficiency decrease is negligible. Therefore, startup and shutdown of the combustion units is not considered to add GHG emissions above those expected from routine equipment operation.

Table 5-1 Proposed GHG Emissions Limits

EPN	Description	Proposed CO_2e Emissions Limit (tpy)
C-6961, B-6961	CO_2 Stripper Vent	233,597
U-2650	Option 1 - Cogen Unit	320,039
U-2651	Option 1 - Auxiliary Boiler 1	140,929
U-2651	Option 1 - Auxiliary Boiler 2	140,929
U-2650, U-2651, U-2652	Option 1 - Cogen Unit/ Auxiliary Boiler Cap	389,094
U-2651	Option 2 - Boiler 1	281,609
U-2652	Option 2 - Boiler 2	281,609
U-2653	Option 2 - Boiler 3	281,609
U-2651, U-2652, U-2653	Option 2 - Boiler Cap	350,912
U-2640	Routine Flaring	1,051
MSS-C	MSS Flaring	227
FUG-1	EO/EG Plant Process Fugitives	13
FUG-2	Steam Plant Process Fugitives	85
MP-2840A	Firewater Pump Engine	22
MP-2840B	Firewater Pump Engine	22
EGEN-1	Emergency Generator Engine	69
MSS-U	Uncontrolled MSS	1
NA	**Plant Total (Option 1)**	**624,180**
NA	**Plant Total (Option 2)**	**585,998**

Section 6
BACT Analysis

6.1 General BACT Issues

6.1.1 BACT Applicability

For this project, 40 CFR § 52.21(j)(3) prescribes BACT applicability as follows:

> A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.

The only PSD pollutant addressed in this permit application is GHG. The new emissions units associated with the Project that emit GHGs are the following:

- CO_2 Stripper vent;
- Steam and electric power generation facilities,
- Process flare,
- Process fugitives,
- Diesel engines for emergency use, and
- Maintenance, startup, and shutdown (MSS) activities.

BACT applies to each of these new sources of GHG emissions. No existing, GHG-emitting emissions units at the Battleground Manufacturing Complex will undergo a physical change or change in method of operation as part of the project.

6.1.2 Methodology for BACT Analysis

BACT is defined in the PSD regulations at 40 CFR § 52.21(b)(12)(emphasis added) as follows:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.

The U.S. EPA-preferred methodology for a BACT analysis for pollutants and sources subject to PSD review is described in a 1987 EPA memo (U.S. EPA, Office of Air and Radiation Memorandum from J.C. Potter to the Regional Administrators, December 1, 1987). This methodology is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. In addition, a control technology must be analyzed only if the applicant opposes that level of control.

In an October 1990 draft guidance document (*New Source Review Workshop Manual (Draft*), October 1990), EPA set out a 5-step process for conducting a top-down BACT review, as follows:

1) Identification of available control technologies;

2) Technically infeasible alternatives are eliminated from consideration;

3) Remaining control technologies are ranked by control effectiveness;

4) Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects in order of most effective control option to least effective; and

5) Selection of BACT.

In its *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), EPA reiterates that this is also the recommended process for permitting of GHG emissions under the PSD program. As such, this BACT analysis follows the top-down approach.

A RACT/BACT/LAER Clearinghouse (RBLC) database search was conducted for CO_2 emissions for all process types. The results of this search are presented in Table B-1 of Appendix B, organized by process type.

6.1.3 Consideration of Global Warming Potential

The GHG emissions from the emissions units identified in Section 6.1.1 comprise emissions of three separate gases: CH_4, CO_2, and N_2O. This fact complicates the BACT analysis because, unlike conventional pollutants, the pollutant GHG includes gases for which the control strategies differ and in some cases compete. For example, as discussed in greater detail in Section 6.8

herein, options for reducing CH_4 emissions frequently rely on combustion. Combustion of methane-containing gases oxidizes the carbon content of those gases to form CO_2, which also is a GHG. Fully combusting one ton of CH_4 forms 2.74 tons of CO_2. Thus, destruction of CH_4 emissions through combustion increases GHG emissions on a mass basis. However, the global warming potential of CH_4 is 21 times higher than that of CO_2, so combustion of CH_4 results in decreases in GHG emissions when expressed on a CO_2e basis.

For the purposes of this BACT analysis, RTP has assumed that reductions of GHG emissions expressed on a CO_2e basis are the primary objectives, so control options involving combustion of CH_4 to form CO_2 are environmentally beneficial. This is consistent with U.S. EPA interpretive guidance:

> [T]o best reflect the impact on the environment, the ranking of control options should be based on the total CO_2e rather than total mass or mass for the individual GHGs. As explained in the Tailoring Rule, the CO_2e metric will "enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (e.g., flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2).

6.1.4 Context for GHG BACT Analysis

The major modification that is the subject of this PSD permit application is the construction of a facility for the manufacture of ethylene oxide and ethylene glycol using proprietary and commercially proven process technologies to meet market demands and provide INEOS with an attractive rate of return on its investment. These are the fundamental objectives and basic design of the proposed project. The BACT analysis presented in Sections 6.2 through 6.8, below, is in this context. Alternative raw materials, production processes, or products that would be inconsistent with these fundamental objectives or basic design would impermissibly redefine the source and are not a part of the BACT analysis.

6.2 CO_2 Stripper Vent

6.2.1 Step 1 – Identification of Potential Control Technologies

The RBLC Database search identified two sources with large CO_2 process vents in Iowa. Table 6-1 presents a summary of the CO_2 controls and emission limits for the vents, both of which are fertilizer manufacturing amine regeneration vents. The control strategy identified in the database for both sources in relation to the vents was good operating practices.

Table 6-1 also presents summary information for two other projects having high concentration CO_2 process vents. As Table 6-1 shows, compression, transport and sequestration are not considered BACT for CO_2 for the projects listed.

For the Iowa projects, the DNR fact sheet stated:

"The following facts are sufficient to eliminate this option without requiring a more detailed site-specific technological or economic analysis:

- the qualitative cost estimate of capture and sequestration is quite high,
- the technological effectiveness for the capture equipment has not been demonstrated in practice yet on a full scale operation,
- there are no commercially available operations, and
- there is uncertainty as to whether locations capable of storing the large amounts of CO_2 that would be produced per year exist within a closer radius of the plant."[1]

Despite the Table 6-1 findings, INEOS recognizes that EPA may consider Carbon Capture and Sequestration (CCS) to be available and technically feasible, at least for large CO_2 sources like CO_2 Stripper Vent. This means that to eliminate CCS adequately and properly, cost must be used as the eliminating factor.

Although the RBLC database specified the CO_2 control for the Iowa permits as good operating practices, the fertilizer plants shown in Table 6-1 are able to use some of the CO_2 from the process vents for the manufacture of urea. As such, the permits state that GHG BACT for the CO_2 vents are to maximize the recovery and use of CO_2. However, the Complex has no process need for CO_2, and as such this option of recovering and using some of the CO_2 emissions is not technically feasible.

As a result, the only additional control options for reducing GHG emissions from the CO_2 Stripper Vent are:

- Selection of an efficient process technology that minimizes production of byproduct CO_2,

1 Prevention of Significant Deterioration (PSD) Permit Review Technical Support Document for Issuance of a PSD Permit for Project Number 12-219, Plant Number 56-10-001 & Project Number 13-037, Plant Number 97-01-030.

- Carbon Capture and Sequestration.

Because this is a high concentration CO_2 stream, the steps required for CCS include only compression, transportation, and sequestration. For the purposes of this analysis, capture, compression, and transport for this stream is considered to be technically feasible. The feasibility of sequestration will be addressed in Step 2.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

Use of an efficient process technology that minimizes the amount of CO_2 produced per amount of ethylene oxide produced is a technically viable and preferred design feature.

The technical feasibility of geological sequestration for control of the CO_2 Stripper Vent is discussed below. A control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source, or there is technical agreement that the technology can be applied to the emission source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option.

The technology must be commercially available for it to be considered as a candidate for BACT. The 1990 Draft Workshop Manual, states, "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."[2]

In general, if a control technology has been "demonstrated" successfully for the type of emission source under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. Page B.17 of the 1990 Draft Workshop Manual states:

> *Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.*

2 New Source Review Workshop Manual, Draft 1990, page B-12.

Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

- *concept stage;*
- *research and patenting;*
- *bench scale or laboratory testing;*
- *pilot scale testing;*
- *licensing and commercial demonstration; and*
- *commercial sales.*

Note some vendors will provide guarantees for commercial sale of technology that has not been sufficiently demonstrated commercially. As further discussed below, such guarantees do not assure commercial success and environmentally compliant operation.

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission source), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission source may not be applicable to a similar source depending on differences in physical and chemical gas stream characteristics. Note that vendor guarantees alone do not constitute technical availability. The 1990 Draft Workshop Manual states the following:[3]

Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, EPA does not consider a vendor guarantee alone to be sufficient justification that a control option will work.

This is because there are many instances where vendor guarantees for emission control equipment have not been met. Vendor guarantees generally do not fully cover the cost of major equipment modifications or installation of new equipment required to attain compliance, the cost of lost production and breached contractual obligations to third parties, and enforcement sanctions for failure to attain environmental compliance.

There are several options being explored and employed for permanent storage of CO_2. These options include storage in various deep geological formations (including saline formations, exhausted oil and gas fields, and unmineable coal seams). Another sequestration option is in salt domes. The technical feasibility of these options is discussed below.

3 Ibid. Page B.20.

Five storage types for geological carbon storage are currently under investigation in North America by the federal government, each with unique challenges and opportunities: (1) oil and gas reservoirs, (2) unmineable coal seams, (3) saline formations, (4) organic-rich shales or basalt formations, and (5) terrestrial ecosystems:[4]

1. Depleted oil and gas reservoirs. These are formations that held recoverable crude oil and natural gas at some time but are no longer economically producing. In general, they are characterized by a layer of porous rock with a layer of non-porous rock which forms a dome. This dome offers great potential to trap CO_2 and makes these formations excellent sequestration opportunities. As a value-added benefit, CO_2 injected into a depleting oil reservoir can enable recovery of additional oil and gas. When injected into a depleted oil bearing formation, the CO_2 dissolves in the trapped oil and reduces its viscosity. This "frees" more of the oil by improving its ability to move through the pores in the rock and flow with a pressure differential toward a recovery well. A CO_2 flood typically enables recovery of an additional 10–15% of the original oil in place. CO_2 enhanced oil recovery (EOR) and enhanced gas recovery (EGR) are commercial processes. It is estimated that 50 to 90 billion metric tons of sequestration potential exists in mature oil and gas reservoirs identified by the Regional Carbon Sequestration Partnerships (RCSPs).[5] There are numerous CO_2 floods in Texas for the purpose of EOR, and some of these are near the Complex. However, sequestration of man-made CO_2 has only recently been conducted.

2. Unmineable coal seams. Unmineable coal seams are those that are too deep or too thin to be mined economically. All coals have varying amounts of methane adsorbed onto pore surfaces, and wells can be drilled into unmineable coal beds to recover this coal bed methane (CBM). Initial CBM recovery methods, dewatering, and depressurization, leave a fair amount of CBM in the reservoir. Additional CBM recovery can be achieved by sweeping the coal bed with nitrogen or CO_2. CO_2 preferentially adsorbs onto the surface of the coal, releasing the methane. Two or three molecules of CO_2 are adsorbed for each molecule of methane released, thereby providing an excellent storage sink for CO_2. Like depleting oil reservoirs, unmineable coal beds are a good early opportunity for CO_2 storage. One potential barrier to injecting CO_2 into unmineable coal seams is swelling. When coal adsorbs CO_2, it swells in volume. In an underground formation swelling can cause a sharp

4 Page 5. The North American Carbon Storage Atlas 2012, U.S. Department of Energy, National Energy Technology Laboratory, et al.
5 Ibid. Page 49.

drop in permeability, which not only restricts the flow of CO_2 into the formation but also impedes the recovery of displaced CBM. Two possible solutions to this challenge include angled drilling techniques and fracturing.

It is estimated that between 14,010 and 32,020 magatonnes of CO_2 sequestration potential exists in unmineable coal seams identified by the RCSPs. Although these seams run through the Texas Gulf Coast, there are no government funded sequestration projects evaluating the potential for using the Texas unmineable coal seams.[6] Accordingly, this CO_2 sequestration technique will not be considered further in this analysis because the technology is not commercially demonstrated.

3. Saline formations. Saline formations are layers of porous rock that are saturated with brine. They are much more commonplace than coal seams or oil and gas bearing rock, and represent an enormous potential for CO_2 storage capacity. The RCSPs estimates a range of 900 to 3,700 billion metric tons of sequestration potential in saline formations. However, much less is known about saline formations than is known about crude oil reservoirs and coal seams, and there is a greater amount of uncertainty associated with their ability to store CO_2. Saline formations contain minerals that could react with injected CO_2 to form solid carbonates. The carbonate reactions have the potential to be both a positive and a negative. They can increase permanence but they also may plug up the formation in the immediate vicinity of an injection well. Additional research is required to better understand these potential obstacles and how best to overcome them. The RCSPs has identified that there is large potential for CO_2 sequestration using saline formations within the vicinity of the proposed Project.[7] However, INEOS is unaware of CO_2 injection studies that would confirm the usability of the Southeastern Texas saline formations for CO_2 sequestration.
   Potential environmental impacts resulting from CO_2 injection that require assessment before a site can be considered acceptable include:

   - Uncertainty concerning the significance of dissolution of CO_2 into brine,
   - Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,

6 The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) fourth edition of the *United States Carbon Utilization and Storage Atlas (Atlas IV)*. Page 8.
7 The North American Carbon Storage Atlas 2012, U.S. Department of Energy, National Energy Technology Laboratory, et al.. Page 18.

- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water, and

- Potential effects on wildlife.

Additionally, it is estimated that it would take six years to find and determine a site suitability for CO_2 sequestration without any guarantee that a suitable site would be found.[8] Accordingly, this CO_2 sequestration technique is considered technically infeasible for the EO/EG Plant.

4. Basalt and Organic Rich Shale formations.[9] Basalts are geologic formations of solidified lava. Basalt formations have a unique chemical makeup that could potentially convert all of the injected CO_2 to a solid mineral form, thus permanently isolating it from the atmosphere. Current research is focused on enhancing and utilizing the mineralization reactions and increasing CO_2 flow within a basalt formation. Although oil and gas-rich organic shale and basalt research is in its infancy, these formations may, in the future, prove to be optimal storage sites for sequestering CO_2 emissions. Since these CO_2 sequestration techniques are in the early research and development phases, they are considered technically infeasible for the EO/EG Plant at this time, and will not be considered further in this analysis.

5. Salt Domes. Salt caverns are cavities or chambers formed in underground salt deposits. Although cavities may naturally form in salt deposits, this analysis discusses caverns that have been or will be intentionally created by humans for specific purposes, such as for storage of petroleum products or disposal of wastes or CO_2. Because of the degree of protection they provide, salt caverns are used for hydrocarbon storage and are being used for disposal of oil field wastes and hazardous liquids.

   Man-made salt caverns are formed through a process called solution mining. First, well-drilling equipment is used to drill a hole from the surface to the depth of the salt formation. The portion of the well above the salt formation is supported by several concentric layers of pipe known as casing to protect drinking water zones and to prevent collapse of the hole. A smaller-diameter pipe called tubing is lowered through the middle of the well. This arrangement creates two pathways into and out of the well – the hollow tubing itself and the

8 Carbon Dioxide Transport and Storage Costs in NETL Studies Quality Guidelines for Energy Systems Studies, Page 15, 1 year for regional evaluation and initial site selections, 2 years for site characterization for 3 sites, and 2 years for permitting.
9 Ibid. Page 19.

open space between the tubing and the final casing (the annulus). To form a salt cavern, the well operator pumps fresh water through one of the pipes. As the fresh water comes in contact with the salt formation, the salt dissolves until the water becomes saturated with salt. The salty brine is then pumped to the surface through the second of the two pipes. Cavern space is created by the removal of salt as brine. Operators typically use a combination of direct and reverse circulation at different times to create the desired cavern shape. Some operators install two wells in their caverns and can alternate injection of fresh water and brine withdrawal between the two wells to achieve the desired size and shape of the cavern.[10]

For the purposes of this analysis, salt domes are not eliminated as technically infeasible for the storage of CO_2, and there are several salt dome hydrocarbon storage facilities within 20 miles of the Complex.

6.2.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

For the proposed CO_2 Stripper Vent, up to 99+% control may be feasible since no separation from a dilute stream is required. This control level assumes that CO_2 does not leak from the sequestration facility. However, two sequestration cases, listed below, will be evaluated in Step 4. Both cases are assumed to be equally effective and are considered to be the most effective control options followed by selection of an efficient process technology.

- Case 1: Sequestration of all the CO_2 in a nearby salt dome,
- Case 2: Sequestration of 50% of CO_2 in a nearby salt dome and 50% EOR sequestration in a nearby oil field, and
- Selection of an efficient process technology that minimizes production of byproduct CO_2.

6.2.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Table 6-2 summarizes the economic, energy, environmental feasibility of the two sequestration options proposed in Step 3.

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10 Argonne National Laboratory for the U.S. Department of Energy, National Petroleum Technology Office; Salt Caverns & Their Use for Disposal of Oil Field Wastes, September 1999

Economic Impacts. The cost of compressing, transporting, and sequestration are derived from a number of reference documents as discussed below. The capital cost of compression and power demand were estimated using Figures 1 and 2 from "Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage."[11] The capital cost from the reference are in 2005 dollars which were escalated to 2012 dollars using the Chemical Engineering Plant Cost Index.

Pipeline costs were estimated using "Quality Guidelines for Energy Systems Studies- Estimating Carbon Dioxide Transport and Storage Costs."[12] From this reference it was determined that for the amount of CO_2 from the CO_2 Stripper Vent, a six inch diameter pipeline would be required. Pipeline length was estimate at 20 miles. The basis for the estimated pipeline length is the distance from the proposed Project located near La Porte, Texas to the hydrocarbon salt dome storage facilities at Mont Belvieu, Texas north of La Porte.

Salt dome storage costs were estimated based on $3.5 per barrel. The salt dome storage costs are believed to be a low estimate from a vendor's website.[13] A much older reference stated that salt dome storage costs in 1997 dollars is between $2 and $6 per barrel.[14]

<u>Sequestration of all CO_2 in Salt Dome</u>

Total capital costs for the sequestration of all the CO_2 in a nearby salt dome option is conservatively estimated to be $171 million (2012 dollars). Of this capital cost $129.1 million is for the salt dome; 76 percent of the total capital investment.

Total annual cost is estimated to be $25.7 million (2012 dollars). The annualized cost breakdown follows:

- Power costs of $2.8 million for 5,500 kilowatts of power for compression at 5.76 cents per kilowatt,[15]
- Operating and maintenance costs for labor and materials of $6.8 million,[16] and

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11 Institute of Transportation Studies University of California, Davis 2006; pubs.its.ucdavis.edu/download_pdf.php?id=1047
12 March 2013, DOE/NTL-2013/1614, Table 2 Pipeline Cost Breakdown. http://www.netl.doe.gov/energy-analyses/pubs/QGESS_CO2T%26S_Rev2_20130408.pdf
13 www.SaltDomeStorage.com
14 Salt Caverns & Their Use for Disposal of Oil Field Wastes, September 1999 page 14. http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/saltcav.pdf
15 5- US EIA Electric Power Monthly; Table 5.6.A. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, November 2012 and 2011 (Cents per Kilowatt-hour); Texas, Industrial Sector.

- Annualized capital costs of $16.1 million.[17]

The resulting cost effectiveness for CO_2 compression, transport, and sequestration of the CO_2 Stripper Vent emissions is $111 per ton. Avoided costs of CO_2 compression, transport, and sequestration of the emissions from the CO_2 Stripper Vent is $124 per ton. Avoided costs subtracts the CO_2 emissions generated from power production. The estimated CO_2 emissions from power production is ~23,000 tons per year. This is estimated by taking the power requirements for the CO_2 compression times an average Btu/kilowatt for generating power from natural gas[18] times the natural gas CO_2 emission factor of 116.9 pounds of CO_2 per million Btu of natural gas.

Sequestration of Half of the CO_2 in Salt Dome

This option looks at sequestering half of the CO_2 Stripper Vent emissions in a salt dome and giving away or selling half of the CO_2 for use in EOR. The option of assuming that all of the CO_2 could be given or sold for the life of the plant has significant risks that subject this option to significant risks and render it infeasible. First, based on Denbury Resources 2012 Fall Analyst presentation, Denbury does not need to purchase CO_2 from man-made (anthropogenic) sources until 2018, two years after startup of the proposed Project.[19] Until then, Denbury has sufficient CO_2 from their Jackson Dome reserves and current contracts from anthropogenic sources (Air Products, PCS Nitrogen, Mississippi Power, Lake Charles Cogeneration, and other industrial partners).[20] As a result, INEOS will need to have a significant amount of salt dome storage in the event of an interruption of supplying CO_2 to the Denbury pipeline, assuming Denbury would agree to take the CO_2. A ten year storage volume was selected as being prudent because the Denbury Resources Analyst presentation only projects out to 2023.[21] Note the economics of using CO_2 for EOR is dependent on crude prices, which are difficult to project out for the short term, much less the long term.

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16 Page 134 of Plant Design and Economics for Chemical Engineers, Peters & Timmerhaus, McGraw Hill Book Company, second edition; average for simple processes.

17 0.094 capital recovery cost based on 20 year life and 7% social cost of money per USEPA Air Pollution Control Manual, 6th edition.

18 8152 Btu/kW from EIA Table 8.1. Average Operating Heat Rate for Selected Energy Sources 2011

19 http://www.slideshare.net/Denbury/fall-analyst-presentation slide 83.

20 Ibid. Slide 82.

21 Actual storage volume required is 15 years = 2036 (20 year Ineos plant operation) minus 2018 (when Denbury needs more anthropogenic $CO_{2)}$ + 2018-2016 (difference between INEOS plant startup and when Denbury needs anthropogenic CO_2).

Total capital costs for the sequestration of half the CO_2 in a nearby salt dome option is conservatively estimated as $106 million (2012 dollars). Of this capital cost, $4.5 million is for the salt dome; 61 percent of the total capital investment.

Total annual cost is estimated to be $15.9 million (2012 dollars). The cost breakdown follows:

- Power costs of $2.8 million for 5,500 kw of power for compression at 5.76 cents per kw,
- Operating and maintenance costs for labor and materials of $4.2 million,
- Sale of half of the CO_2 to Denbury at $10 per ton of CO_2 is $1.2 million in savings,[22] and
- Annualized capital costs of $10.0 million.

The resulting cost effectiveness for CO_2 compression, transport, and sequestration of the CO_2 Stripper Vent emissions is $69 per ton. Avoided costs of CO_2 compression, transport, and sequestration of the these emissions are $76 per ton. Avoided costs subtracts the CO_2 emissions generated from power production. The estimated CO_2 emissions from power production is ~23,000 tons per year. This is estimated by taking the power requirements for the CO_2 compression times an average Btu/kilowatt for generating power from a natural gas times the natural gas firing CO_2 emission rate of 116.9 pounds of CO_2 per million Btu of natural gas.[23]

Energy Impacts. The energy impacts at the proposed Project are the same for both disposal options. For CO_2 compression and pumping, it is estimated that 5,500 kilowatts of power are required.

Environmental Impacts. The environmental benefit impacts of both options are the same with the sequestration of 231,261 tons per year of CO_2, and 4,625,216 ton over twenty years. The environmental disbenefits are also the same with the emissions of the following pollutants required for power generation.

22 $10 per ton price for CO_2 is round up from Denbury's 2009 Fall Analyst slide show slide 49 footnote 1 "Emitter owns and installs capture equipment, Denbury would construct pipeline, CO_2 Price - $0.44/Mcf @ $60 oil". RTP contacted Michael K. Knaggs, Director, Office of Major Demonstrations Strategic Center for Coal National Energy Technology Laboratory on July 25, 2013 to obtain the selling price of CO_2 to Denbury for the Air Products demonstration project who stated "We know that Denbury is paying Air Products for the CO_2 delivered to the Denbury line, but the amount of that payment is unknown to us. Even if we knew the amount, it is highly business-sensitive and we would be unable to share it publicly."

23 http://www.eia.gov/electricity/annual/html/epa_08_01.html

NSR Pollutant	lb/MMBtu	tons/year
NO_x	0.099	19.4
CO	0.015	2.9
VOC	0.0021	0.4
$PM_{2.5}$	0.0066	1.3
SO_2	0.0034	0.7

Selection of Efficient Process Technology

There are no costs or negative environmental impacts associated with selection of an efficient process technology that maximizes conversion of ethylene to ethylene oxide thus reducing the amount of CO_2 formation. This option also reduces raw material consumption which conserves resources and minimizes production costs.

6.2.5 Step 5 – Selection of BACT

INEOS has concluded that CCS is not feasible. With respect to economic feasibility, CCS costs of $76 to $124 per ton are not supported by current carbon credit markets:

- Recent estimated prices for CO_2 credits in Europe in early 2013 are 8 to 10 euros ($10 to $13 US) for carbon allowances.[24]
- "The Green Exchange" lists average annual prices for California Carbon Allowances Futures of $14.45, $14.55, and $14.40 for June 2013, December 2013, and December 2014, respectively. [25]

The above finding of cost unreasonableness for CCS is consistent with recent GHG BACT determinations for high-concentration process vents presented in Table 6-1 where BACT cost effectiveness values of $43 and $80 per ton of CO_2 were determined to be unreasonable.

The estimated total capital cost of the proposed Project is $1,100,000,000. Based on a 7% interest rate, and 20 year equipment life, this capital cost equates to an annualized cost of about $104,000,000 for the project without CCS. Thus, the annualized cost of CCS would be about 15% to 25% of the cost of the project without CCS. An additional cost of this magnitude would make the Project economically unviable; therefore, CCS was rejected as a control option on the basis of excessive cost.

24 EU to Sell 197 Million of CO2 in Early 2013, New Energy Says; http://www.bloomberg.com/news/2012-10-19/eu-to-sell-197-million-of-co2-in-early-2013-new-energy-says-1-.html [2/7/2013 1:52:58 PM]
25 Average Bid Price Monday, June 10, 2013 - BGC Carbon Market Daily, California Carbon Allowance Futures.

INEOS has concluded that use of a process technology that provides low raw material (ethylene) usage and high yield of EO and a low production of by-product CO_2 relative to the production of EO is BACT for the CO_2 Stripper Vent. INEOS proposes the following limits:

- A twelve month rolling emissions limit of 233,597 tons of CO_2e per year, and
- A twelve month rolling emission rate of 0.39 tons of CO_2e per ton of ethylene oxide produced.

These limits are similar in form to those found in Table 6-1.

6.3 Cogeneration Facility

Steam and power Option 1 is a cogeneration unit consisting of a combustion turbine and duct-fired HRSG and two boilers to provide backup steam. This section of the BACT analysis addresses the cogeneration unit only with the exception of the evaluation of CCS. It is assumed that if CCS was a viable control option, the exhaust from both the cogeneration unit and the boilers would be routed to a single CCS facility designed to handle both. As Option 2 also includes two backup that would be identical to those in Option 1, the boiler BACT analysis for Option 2 in Section 6.3 applies to Option 1 as well.

6.3.1 Step 1 – Identification of Potential Control Technologies

Although the proposed facility does not include a steam cycle condensing turbine and is not a combined cycle plant, the facility does include an HRSG and is configured similarly enough to a combined cycle gas turbine to warrant evaluation of any combined cycle facilities. The RBLC Database search identified use of natural gas fuel, good design and operating practices, good combustion technology, waste heat recovery, and good maintenance as GHG control strategies for gas fired combustion sources of all types, including combustion turbines. These and additional control technologies identified below were included in the BACT analysis.

<u>High Efficiency Turbines and HRSG</u>

*Turbine Desig*n – The proposed turbine is rated at 47 MW with a manufacturer specified thermal efficiency of 11,628 Btu/kw-hr at site operating conditions in simple cycle mode. The turbine will be used to generate hot exhaust gases for combined heat and power generation. Therefore, a direct comparison of thermal efficiency to either a simple cycle or combined cycle turbine used solely for electricity generation is not appropriate. Electricity generating gas turbines units (EGUs) are designed to optimize the conversion of energy to mechanical work rather than transfer energy to a medium such as process steam. Further, a combined cycle unit uses two thermodynamic cycles, the Brayton cycle and the Rankine cycle, to convert thermal energy into mechanical work. Electricity is produced by expanding exhaust gases through the gas turbine and by passing steam through a steam turbine to drive a shaft which converts mechanical work into electricity. Energy is consumed in order to drive the turbine mass resulting in mechanical energy losses and a decrease in thermal efficiency. A CHP plant does not generate electricity in a steam turbine and therefore, does not experience the mechanical energy loss resulting from driving the turbine. Instead, the energy in the steam is used through conductive heat transfer in the process (EO/EG production in this instance). As a result, CHP is an inherently more efficient process than an equivalent combined cycle turbine. For these reasons, comparing thermal efficiency on an energy-to-power basis to either a simple or combined cycle turbine EGU to a gas turbine designed for steam production is not appropriate.

Combustion turbines operate at high temperatures. Heat radiated by the hot turbine components is lost to the surrounding atmosphere. To minimize this heat loss, turbines can be wrapped with insulating blankets such that more of the heat is retained in the hot gases allowing it to be recovered as useful energy.

HRSG Design – Efficient design of the HRSG improves overall thermal efficiency. This includes the following: finned tube, modular type heat recovery surfaces for efficient, economical heat recovery; use of an economizer, which is a heat exchanger that recovers heat from the exhaust gas to preheat incoming HRSG boiler feedwater to attain industry standard performance (IMO) for thermal efficiency; use of a heat exchanger to recover heat from HRSG blowdown to preheat feedwater; use of hot condensate as feedwater which results in less heat required to produce steam in the HRSG, thus improving thermal efficiency; and application of insulation to HRSG surfaces and steam and water lines to minimize heat loss from radiation.

<u>Fuel Gas Pre-Heating</u>

Additional processes such as fuel gas heating can improve overall efficiency of the project. The overall efficiency of the combustion turbine can be increased by pre-heating the fuel prior to combustion. This is usually accomplished by heat exchange with hot water from the HRSG the combustion turbine.

Good Combustion, Operating and Maintenance Practices

Good combustion, operating and maintenance practices improve fuel efficiency of the combustion turbines by ensuring optimal combustion efficiencies are achieved as intended in the design of the burner. Good operating practices include the use of operating procedures including startup, shutdown and malfunction, the use of instrumentation and controls for operational control, and maintaining manufacturer recommended combustion parameters. Maintenance practices include complying with manufacturer recommended preventative maintenance.

Periodic Maintenance and Tune-up – Periodic tune-up of the turbines helps to maintain optimal thermal efficiency. After several months of continuous operation of the combustion turbine, fouling and degradation results in a loss of thermal efficiency. A periodic maintenance program consisting of inspection of key equipment components and tune up of the combustor will restore performance to near original conditions. The manufacturer of the proposed turbine has an extensive inspection and maintenance program that INEOS can implement.

Minimizing Fouling of Heat Exchanger Surfaces – Fouling of interior and exterior surfaces of the heat exchanger tubes in the HRSG hinders the transfer of heat from the hot combustion gases to the boiler feedwater. This fouling occurs from contaminants in the turbine inlet air and in the feedwater. Fouling is minimized by inlet air filtration, maintaining proper feed water chemistry, and periodic maintenance consisting of cleaning of the tube surfaces during equipment outages.

Instrumentation and Controls – Proper instrumentation ensures efficient turbine operation to minimize fuel consumption and resulting GHG emissions. Today's turbines, like those being considered for this project, are equipped with a digital control package included. These systems control turbine operation, including fuel and air flow, to optimize combustion for control of criteria pollutant emissions (NO_x and CO) in addition to maintaining high operating efficiency to minimize fuel usage over the full range of operating conditions and loads.

Waste Heat Recovery

The exhaust gas from a simple cycle turbine contains a significant amount of heat that is "wasted" when exhausted directly to the atmosphere. Routing the exhaust gas through a heat recovery steam generator (HRSG) to produce steam for process use or to feed a steam turbine which generates additional electric power is the single most effective means of increasing the efficiency of combustion turbines. The overall efficiency can be increased from about 30% for a simple cycle (no heat recovery) unit to about 50% for a cogeneration or combined cycle unit. In applications where process heat is needed, the steam produced in the HRSG is used to provide heat to plant processes in addition to or instead of being used to produce additional electricity.

Fuel Selection

Natural gas is the lowest carbon fossil fuel that exists. Fuels gases that contain significant amounts of hydrogen which produces no CO_2 when burned can be burned in turbines and duct burners if available and is an effective means of reducing GHG emissions in such situations.

Carbon Capture and Sequestration

Capture and compression, transport, and geologic storage of the CO_2 is a post-combustion technology that is not considered commercially viable at this time for natural gas combustion sources. However, based on requests by EPA Region 6 for other GHG permit applications, Carbon capture and sequestration (CCS) is evaluated further in this analysis.

6.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered “technically” feasible for the proposed turbines. However, CCS is not considered to be a viable alternative for controlling GHG emissions from natural gas fired combustion facilities at the current time. This conclusion is supported by the BACT example for a natural gas fired boiler in Appendix F of EPA’s *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010). In the EPA example, CCS is not even identified as an available control option for natural gas fired facilities.

The CO_2 stream from the cogeneration unit exhaust is similar in nature to the gas-fired industrial boiler in the EPA Guidance Appendix F example, which are dilute streams, and thus are not viable candidates for CCS due to the high capital and operating cost of the facilities required to separate the CO_2 from the remainder of the stream.

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Fuels used in industrial process and power generation typically include coal, fuel oil, natural gas, and process fuel gas. Of these, natural gas is typically the lowest carbon fuel that can be burned, with a CO_2 emission factor in lb/mmBtu about 55% of that of subbituminous coal. Process fuel gas is a byproduct of chemical processes that typically contains a higher fraction of longer chain carbon compounds than natural gas and thus results in more CO_2 emissions. Table C-2 in 40 CFR Part 98 Subpart C, which contains CO_2 emission factors for a variety of fuels, gives a CO_2 factor of 59 kg/mmBtu for fuel gas compared to 53.02 kg/mmBtu for natural gas. Of over 50 fuels identified in Table C-2, coke oven gas, with a CO_2 factor of 46.85 kg/mmBtu, is the only fuel with a lower CO_2 factor than natural gas, and is not an available fuel for the proposed project. Use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by up to 100%. Hydrogen fuel, in any concentration, is not a readily available fuel for most facilities and is only a viable low carbon fuel at industrial plants that generate hydrogen internally. Hydrogen will not be produced by the EO/EG process and is not an available fuel for the proposed cogeneration unit. Natural gas is the lowest carbon fuel available for use in the proposed facilities; thus, use of low carbon fuel other than natural gas was eliminated due to lack of availability for the proposed facilities.

6.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies that were considered for controlling GHG emissions from the proposed turbines in order of most effective to least effective include:

- CO_2 capture and storage,
- Waste heat recovery,
- Instrumentation and control system,
- Turbine design,
- HRSG design,
- Minimizing fouling of turbine/HRSG,
- Fuel pre-heating, and
- Periodic maintenance and tune-ups.

CO_2 capture and storage may be capable of achieving 90% reduction of produced CO_2 emissions and thus is considered to be the most effective control method.

Exhaust waste heat recovery can take several forms, and use of an HRSG to produce process steam can increase thermal efficiency from around 30% for a simple cycle unit to about 50%, which is equivalent to about a 40% reduction in CO_2e emissions.

An instrumentation and control package to continuously monitor the turbine package ensures the turbine is operating in the most efficient manner. Instrumentation and controls include:

- Gas flow rate monitoring,

- Fuel gas flow and usage,
- Exhaust gas temperature monitoring,
- Pressure monitoring around the turbine package,
- Temperature monitoring around the turbine package,
- Vibration monitoring,
- Air/fuel ratio monitoring, and
- HRSG Unit temperature and pressure monitoring.

Periodic maintenance and tune-ups of turbines are typically performed per the manufacturer's recommended program. These programs consist of thorough inspection and maintenance of all turbine components on a daily, monthly, semi-annual, or annual frequency depending on the parameter or component and as recommended by the turbine vendor.

The effectiveness of instrumentation and control, maintenance and tune-ups, fuel preheating, and the remaining efficiency improvement options cannot be precisely quantified, and are estimated to be up to 3%, Ranking them in order of effectiveness would not be meaningful.

6.3.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

A brief evaluation of each technically feasible combustion turbine control option follows.

CCS. The technology to capture and store CO_2 in permanent underground storage facilities exists and has been used in limited applications, but as stated previously, is not a technically or economically viable for most commercial applications. However, since the technology has been demonstrated on some processes and is potentially feasible for the proposed combustion turbine and boilers, it cannot be completely ruled out based only on technical infeasibility; therefore, an impact analysis was performed for this option.

Economic Impacts. There have been numerous studies estimating the energy requirements and costs of CCS systems. Most of these studies have been focused on large coal- and natural gas-fired electric power plants. Because the natural gas-fired turbine and boilers will have a flue gas composition very similar or the same as natural gas fired electric power plants, a 2010 report by the National Energy Technology Laboratory of the U.S. Department of Energy (the "NETL report") was used as the primary basis for estimating CCS system energy requirements and costs.[26]

26 Capital costs were updated to 2011 dollars in a more recent study: Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases: August 2012 DOE/NETL-341/082312.

Table 6-3 presents the estimated costs of carbon capture and compression for the proposed combustion turbine and boilers using the NETL report. The natural gas combined cycle (NGCC) plant evaluated in the NETL report has a nominal heat input of 3,765 MMBtu/hr, and emissions 1.9 million tons of CO_2 per year. The proposed new combustion turbine and boilers have a design heat input of 759 MMBtu/yr and emit 0.4 million tons of CO_2 a year. As a result, adjustments were made to the NETL report capital and operating costs to accommodate the smaller size equipment as follow:

- Capital costs were adjusted by the ratio of the heat inputs to the 6 tenth power,[27] and
- Operating and maintenance costs were adjusted by the ratio of the heat inputs.

As Table 6-3 shows, the avoided cost of CO_2 capture and compression is $174 per ton. The cost of a pipeline and sequestration by salt dome storage would be similar to that of the CO_2 Stripper Vent, adding $124 per ton. This gives a total cost of sequestration for these small sources of CO_2 of $297 per ton of CO_2.

Energy Impacts. The energy impacts of carbon capture and compression are large requiring over 5,700 kilowatts of power and 124,000 pound per hour of steam.

Environmental Impacts. The negative environmental impacts of the energy requirements result in the following emissions:

NSR Pollutant	lb/MMBtu	tons/year
NOx	0.099	48.5
CO	0.015	7.4
VOC	0.0021	1.0
$PM_{2.5}$	0.0066	3.2
SO_2	0.0034	1.7

The estimated total capital cost of the proposed project is $1,100,000,000. Based on a 7% interest rate, and 20 year equipment life, this capital cost equates to an annualized cost of about $104,000,000 for the project without CCS. Thus, the annualized cost of CCS would be about 91% of the cost of the project without CCS. An additional cost of this magnitude would make the project economically unviable; therefore, CCS was rejected as a control option on the basis of excessive cost.

27 Cost estimates can be approximated for equipment where capital cost data are available for similar projects but of different capacity. In general, costs do not rise in strict proportion to size. On the average, capital costs rise by the exponent of 0.6, and the relationship is referred to as the six-tenths factor ratio. From Cost and Optimization Engineering, F. C. Jelen, McGraw-Hill Book Company 1970.

Based on both the excessive annual cost and cost effectiveness of GHG emissions control and the inability of the project to bear the high cost and the associated negative environmental and energy impacts, CCS is rejected as a control option for the proposed cogeneration unit and backup boilers.

Instrumentation and Controls. Instrumentation and controls that can be applied to the combustion turbines/HRSGs are identified in Section 6.2.3 and are considered an effective means of control for the proposed turbine configuration.

Waste Heat Recovery. Heat recovery systems consisting of an HRSG to produce process steam turbine and other practices and design features identified in Section 6.2.1, that are designed to recover and utilize the waste heat in the turbine/HRSG, are capable of effectively reducing GHG emissions by about 40% compared to a combustion turbine alone that exhausts to the atmosphere without any form of exhaust heat recovery.

Periodic Maintenance and Tune-ups. Periodic maintenance and tune-ups of the turbine include:

- Preventive maintenance check of fuel gas flow meters annually,
- Cleaning of combustors on an as-needed basis, and
- Implementation of manufacturer's recommended inspection and maintenance program.

These and the remaining options listed below insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement.

- Turbine design,
- HRSG design,
- Minimizing fouling of turbine/HRSG, and
- Fuel pre-heating.

6.3.5 Step 5 – Selection of BACT

The proposed design and operating practices are proposed as BACT for the cogeneration unit:

- Waste heat recovery in the form of an HRSG to produce steam for use in the EO/EG process;
- Use of natural gas (note: about 5% of the heat input will come from process vents that have a carbon content equal to that of natural gas on a CO_2 lb/mmBtu basis);
- Good combustion, operation, and maintenance practices; and
- Installation and use of a fuel preheater.

INEOS proposes an annual emission limit of 320,039 tpy of CO_2e for the cogeneration unit alone, and an annual emissions limit of 389,094 tpy of CO_2e for the cogeneration unit and backup boilers combined, both of which include emissions from maintenance, startup, and shutdown activities. These proposed emission limits are based on a 365-day rolling average that will be calculated based on fuel monitoring and emission factors determined based on periodic fuel analyses.

INEOS also proposes a thermal efficiency limit for the cogeneration unit of 7,720 Btu/kw-hr equivalent, based on a 365-day rolling average. Thermal efficiency will be calculated using equations that put the energy recovered by a cogeneration facility on an equivalent basis to a plant that generates only electric power, referred to as Fuel Chargeable to Power (FCP). The following equations from *Cogeneration Application Considerations*, General Electric, May 2009, will be used:

$$FCP = (Q_{GT} - FCS)/P_{NET}$$

Where:
- FCP = Fuel Chargeable to Power, Btu (HHV)/kw-hr
- Q_{GT} = Heat Input to gas turbine and duct burner, mmBtu/hr
- FCS = Fuel Chargeable to Steam, mmBtu/hr
- P_{NET} = Net electrical production, kw.

Fuel Chargeable to Steam (FCS) is the net heat used to generate steam divided by the efficiency of an equivalent boiler, calculated as follows:

$$FCS = (Q_{HP} + Q_{LP} - Q_{FW}) / e_{boiler}$$

Where:
- FCS = Fuel Chargeable to Steam, mmBtu/hr
- Q_{HP} = Heat content of high pressure steam, mmBtu/hr
- Q_{LP} = Heat content of low pressure steam, mmBtu/hr
- Q_{FW} = Heat content of feedwater, mmBtu/hr
- e_{boiler} = Efficiency of an equivalent boiler, 0.84.

The heat used to generate steam for each of the above heat requirements is the product of the change in enthalpy required to convert water to steam of the specified pressure and temperature and the production rate of the steam. The heat used to heat the feedwater is the change in enthalpy to bring the feedwater to vaporization temperature and mass flow rate. These heat rates are calculated as follows:

$$Q_i = \Delta h_i \times m_i$$

Where:
- Q_i = Heat used for steam or water stream i, (mmBtu/hr)
- Δh_i = Change in enthalpy of stream i, (mmBtu/lb)
- m_i = Mass flow of stream i, (lb/hr).

6.4 Boilers

Natural gas fired boilers will be the primary source of steam and power under Steam Option 2. One boiler will operate continuously at full load as the primary boiler, and 2 boilers will operate at 10% of capacity to be available as a backup steam source. As explained in Section 6.3, with the exception of the CCS analysis, the following BACT analysis also applies to the backup boilers in Option 1.

6.4.1 Step 1 – Identification of Potential Control Technologies

The potentially applicable technologies to minimize GHG emissions from the boilers include the following:

- Good combustion practices via improved process controls.
- Boiler Design – Good boiler design to maximize thermal efficiency,
- Routine Boiler Maintenance - Periodically tune-up the boiler to maintain optimal thermal efficiency.
- Waste Heat Recovery - Recovery of waste heat in the boiler blowdown to heat the fuel or combustion air and use of economizers to heat the boiler feedwater with the boiler flue gases increase overall thermal efficiency.
- Use of Low Carbon Fuels – Use of low carbon fuels other than natural gas was addressed in Section 6.3 for the cogeneration option and are not addressed separately for the boilers.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2.

A RACT/BACT/LAER Clearinghouse (RBLC) search was also conducted in an attempt to identify BACT options that have been implemented or proposed for other similar gas fired boilers. The RBLC Database search identified use of natural gas fuel, good operating practices, design, and combustion technology, waste heat recovery, and good maintenance as GHG control strategies for gas fired combustion sources of all types, including boilers. Information from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008) was also used in the preparation of this analysis.

6.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible. As discussed in Section 6.3.2 for the cogeneration option, per EPA's GHG permitting guidance document, CCS is not considered to be a viable option for gas fired combustion sources. However, at the request of EPA Region 6, CCS is retained in the analysis for further consideration.

6.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies applicable to the proposed boilers design in order of most effective to least effective include:

- Carbon capture and sequestration (90%),
- Boiler Design (up to 26%),
- Routine planned maintenance tune-up (up to 10%),
- Waste Heat Recovery, and
- Use of low carbon fuel (natural gas).

CO_2 capture and storage may be capable of achieving 90% reduction of produced CO_2 emissions and thus is considered to be the most effective control method.

Good boiler design and periodic tune-ups are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as new equipment; thus, the higher end of the range of stated efficiency improvements that can be realized is assumed to apply to the existing (older) facilities, with the lower end of the range being more applicable to new boiler designs.

Heat recovery involves the use of economizers to transfer the excess heat from the boiler flue gases to the boiler feed water streams. Pre-heating of boiler feed water stream in this manner reduces the heat requirement of the boilers.

Use of natural gas, the lowest carbon fuel available at the plant, is a viable and preferred fuel.

6.4.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

CCS. The technology to capture and store CO_2 in permanent underground storage facilities exists and has been used in limited applications, but as stated previously, is not economically viable for most commercial applications. However, since the technology has been demonstrated on some processes and is potentially feasible for the proposed cogeneration unit and backup boilers, it cannot be completely ruled out based only on technical infeasibility; therefore, a cost effectiveness analysis is discussed for this option. The three boiler option has emissions of CO_2 very similar to the combustion turbine/boiler option. As such, the costs and cost effectiveness of carbon capture and compression are similar to those found on Table 6-3: CO_2 avoided cost effectiveness of $174 per ton. Similarly, the overall cost effectiveness of CCS would be about $297 per ton. Similarly, the annualized cost of CCS would be about 91% of the cost of the project without CCS. An additional cost of this magnitude would make the project economically unviable; therefore, CCS was rejected as a control option on the basis of excessive cost.

Waste Heat Recovery. Waste heat recovery features including economizers and boiler blowdown heat recovery are cost effective efficiency improvement measures that have no adverse impacts requiring consideration.

Boiler Design. New boilers can be designed with efficient burners, more efficient heat transfer, state-of-the-art refractory and insulation materials in the boiler walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. The function and near steady state operation of the boilers allows them to be designed to achieve “near best” thermal efficiency.

Periodic Boiler Maintenance Tune-ups. Periodic tune-ups of the boilers include:

- Preventive maintenance check of fuel gas flow meters annually,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to precisely quantify an efficiency improvement.

6.4.5 Step 5 – Selection of BACT

INEOS proposes the following technologies as BACT for the primary and backup boilers:

- Use of low carbon natural gas fuel (note: about 5% of the heat input will come from process vents that have a carbon content equal to that of natural gas on a CO_2 lb/mmBtu basis),
- Good boiler design to maximize heat transfer efficiency and to reduce heat loss,
- Use of blowdown heat recovery system,
- Use of economizers to pre-heat boiler feedwater with heat in the flue gases,

- Use of condensate return system,
- Install, utilize, and maintain an automated fuel control system to maximize combustion efficiency on the boilers,
- Clean heater burner tips and convection tubes as needed,
- Determine CO_2e emissions from boilers based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance, and
- Calibrate and perform preventive maintenance on the fuel flow meter once per year.
- INEOS also proposes a minimum thermal efficiency of for the three boilers combined for periods when each boiler is operating as the primary boiler. Compliance with this efficiency limit will be determined on a 365-day rolling average basis and will be calculated for each operating hour from the following equation:

$$\text{Efficiency (\%)} = m_s \times (h_s - h_{fw})/(m_f \times HHV) \times 100$$

Where:

m_s = mass rate of steam flow (lb/hr)
h_s = enthalpy of steam leaving boiler, Btu/lb
h_{fw} = enthalpy of water entering boiler, Btu/lb
m_f = mass rate of fuel flow, lb/hr
HHV = higher heating value of fuel, Btu/lb.

6.5 Flare

It was concluded that a flare is the only technically feasible control option for vent streams at the proposed EO/EG Plant. The RBLC Database search identified good combustion and operating practices as the only GHG control technologies for flares. The flare will be designed and operated consistent with the TCEQ's BACT guidance as outlined in *Air Permit Technical Guidance for Chemical Sources: Flares and Thermal Oxidizers, October 2000 (Draft)*, which specifies that all flares shall comply with the requirements in NSPS, Subpart A, Section 60.18.

The flare will be:

- Designed to maintain the maximum tip velocity and heating value requirements in NSPS Subpart A, Section 60.18 to ensure flame stability and sufficient destruction efficiency;
- Equipped with a continuously burning pilot;
- Equipped with a pilot monitoring system and an automatic re-ignition system;
- Equipped with a remote infrared flame monitor to ensure flame integrity;
- Equipped with a liquid knockout drum to remove any water and condensables from the gas stream prior to flaring; and

- Designed for smokeless operation.

GHG emissions, primarily CO_2, are generated from the combustion of waste gas streams from the proposed units and assist natural gas used to maintain the required minimum heating value to achieve adequate destruction.

6.5.1 Step 1 – Identification of Potential Control Technologies

The only viable control option for reducing GHG emissions from flaring is minimizing the quantity of flared waste gas and natural gas to the extent possible. The technically viable options for achieving this include:

- Flaring minimization – minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practice.
- Proper operation of the flare – use of flow and composition monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and the resulting CO_2.
- Use of a thermal oxidizer in lieu of a flare.

6.5.2 Step 2 – Elimination of Technically Infeasible Alternatives

Both flaring minimization and proper operation of the flare are considered technically feasible. One of the primary reasons that a flare is considered for control of VOC in the process vent streams is that it can also be used for emergency releases. Although every possible effort is made to prevent such releases, they can occur, and the design must allow for them. A thermal oxidizer is not capable of handling the sudden large volumes of vapor that could occur during an upset release. A thermal oxidizer would also not result in a significant difference in GHG emissions compared to a flare. Thus, although a thermal oxidizer may be a more effective control alternative than a flare for VOC emissions, it does nothing to reduce GHG emissions. For this reason, even if a thermal oxidizer was used for control of routine vent streams, the flare would still be necessary and would require continuous burning of natural gas in the pilots, which add additional CO_2, NO_x, and CO emissions.

For these reasons, use of either a thermal oxidizer is rejected as technically infeasible for the proposed project.

6.5.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Flare minimization and proper operation of the flare are potentially equally effective but have case-by-case effectiveness that cannot be quantified to allow ranking.

6.5.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Use of an analyzer(s) to determine the heating value of the flare gas to allow continuous determination of the amount of natural gas needed to maintain a minimum heating value of 300 Btu/scf to insure proper destruction of VOCs ensures that excess natural gas is not unnecessarily flared. This added advantage of reducing fuel costs makes this control option cost effective as both a criteria pollutant and GHG emission control option. There are no negative environmental impacts associated with this option. Proper design of the process equipment to minimize the quantity of waste gas sent to the flare also has no negative economic or environmental impacts.

6.5.5 Step 5 – Selection of BACT

INEOS proposes use of both identified control options to minimize GHG emissions from flaring of process vents from the proposed facilities. Flaring will be minimized by routing process vent streams to the steam generating facilities to the extent possible. By firing these streams in the stream generating units, they will replace natural gas that would otherwise be fired, resulting in no net increase in GHG emissions due to the higher carbon factors of the combined vent streams being the same as that of natural gas. Flare system analyzers will be used to continuously monitor the combined waste gas stream sent to the flare from the proposed and other existing facilities to determine the quantity of natural gas required to maintain a minimum heating value of 300 Btu/scf and also to limit the quantity of natural gas use only what is needed to maintain 300 Btu/scf. The efficient use of natural gas will avoid the production of both unnecessary GHG emissions as well as criteria pollutants.

6.6 Process Fugitives

Hydrocarbon emissions from leaking piping components, (fugitives), in the process (EPN FUG-1PDH) and in the natural gas pipeline (EPN FUG-2) associated with the proposed project include methane, a GHG. The additional methane emissions from fugitives have been conservatively estimated to be 13.3 tpy as CO_2e from EPN FUG-1 and 83.8 tpy as CO_2e from EPN FUG-2 as CO_2e. This is a negligible contribution to the total GHG emissions; however, for completeness, they are addressed in this BACT analysis.

6.6.1 Step 1 – Identification of Potential Control Technologies

The only identified control technology for process fugitive emissions of CO_2e found in the RBLC Database was use of a leak detection and repair (LDAR) program. LDAR programs vary in stringency as needed for control of VOC emissions; however, due to the negligible amount of GHG emissions from fugitives, LDAR programs would not be considered for control of GHG emissions alone. As such, evaluating the relative effectiveness of different LDAR programs is not warranted.

6.6.2 Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

6.6.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As stated in Step 1, this evaluation does not compare the effectiveness of different levels of LDAR programs.

6.6.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur as process fugitives is clearly cost prohibitive. However, if an LDAR program is being implemented for VOC control purposes, it will also result in effective control of the small amount of GHG emissions from the same piping components. INEOS will use TCEQ's 28LAER LDAR program to minimize process fugitive VOC emissions from the EO/EG Plant and associated steam plant. 28LAER is TCEQ's most stringent LDAR program, developed to satisfy LAER requirements in ozone non-attainment areas.

6.6.5 Step 5 – Selection of BACT

Due to the negligible amount of GHG emissions from process fugitives, the only available control, implementation of an LDAR program, is clearly not cost effective, and BACT is determined to be no control. However, INEOS will implement TCEQ's 28LAER LDAR program for VOC BACT/LAER purposes, which will also effectively minimize GHG emissions. Therefore, the proposed VOC LDAR program more than satisfies GHG BACT requirements.

6.7 Firewater Pump and Emergency Generator Engines

The diesel engines will be used for emergency purposes only, and the only non-emergency operation will be for testing one hour per week each, or 52 weeks/yr.

6.7.1 Step 1 – Identification of Potential Control Technologies

The RBLC database did not include any control technologies for GHG emissions from emergency use engines other than use of certified engines and good combustion practices. The technologies that were considered for the engines included:

- Low carbon fuel,
- Good combustion practice and maintenance, and
- Limited operation.

6.7.2 Step 2 – Elimination of Technically Infeasible Alternatives

Use of lower carbon fuel such as natural gas is not considered feasible for an emergency engine. Natural gas supplies may be unavailable in emergency situations, and maintaining the required fuel in an on-board tank associated with each engine is the only practical fuel option. Good combustion practice and maintenance and limited operation are both applicable and feasible.

6.7.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Limited operation and good combustion practices and maintenance are all effective in minimizing emissions, but do not lend themselves to ranking by effectiveness.

6.7.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Limited operation is directly applicable to the proposed engines since they are for emergency use only, resulting in no emissions at most times. Operation for testing purposes is necessary to ensure operability when needed. Properly designed and maintained engines constitutes good operating practice, maximizing efficiency of all fuel combustion equipment, including emergency engines.

6.7.5 Step 5 – Selection of BACT

INEOS proposes to use properly designed and maintained engines to minimize emissions. Emergency use only inherently results in low annual emissions and normal operation will be limited to 52 hours per year for scheduled testing only. This minimal use results in an insignificant contribution to the total project GHG emissions making consideration of additional controls unwarranted. These practices are proposed as BACT for GHG emissions from the engines.

6.8 Maintenance, Startup, and Shutdown

GHG emissions from planned Maintenance, Startup, and Shutdown (MSS) activities will consist primarily of CO_2 from combusting HC in the process flare from the purging of various process vessels and piping to the when shut down for maintenance prior to opening to the atmosphere and methane emissions in the remaining HC that is released to the atmosphere when the equipment is opened. BACT for the flare operation is addressed in Section 6.5.

Methane is a significant component of many of the process fluids that would be released to the atmosphere in larger quantities if not flared. Flaring converts the methane to CO_2, which is also a GHG. However, due to the much higher global warming potential of methane, combustion of the methane results in a net GHG emissions reduction of about 87% when expressed on a CO_2e basis. The amount of methane released directly to the atmosphere is minimized by purging the equipment down to about a 10,000 ppmv HC concentration prior to opening it to the atmosphere. These control practices are the only technologies available for minimizing GHG emissions from planned MSS activities and are this concluded to be BACT.

Table 6-1 Summary of GHG BACT Controls and Limits for CO_2 Process Vents

RBLC ID NO.	FACILITY NAME	PERMIT DATE	PROCESS DESCRIPTION	CAPACITY	CONTROL	EMISSION LIMIT	Estimated CO_2 Sequestration Costs
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	07/12/2013	Nitrogenous fertilizer manufacturing Carbon Dioxide Regenerator	111.15 tons ammonia/hr (2425 metric tons/day-calculated)	good operating practices maximizing the recovery and use of CO_2	1.26 LB/TON OF AMMONIA	See text
*IA-0105	IOWA FERTILIZER COMPANY	10/26/2012	Nitrogenous fertilizer manufacturing CO_2 Regenerator	3012 metric tons/day	good operating practices	1,211,847 TONS/YR (1.1 lb/ton of ammonia-calculated)	See Text
SD [a]	HYPERION ENERGY CENTER	09/15/2011	Petroleum Refinery - Coke/Coal Gasification Rectisol CO_2 vent	400,000 barrels per day of crude oil	None specified	58.6 tons per thousand barrels of crude oil (8,555,600 tons per year)	$43 per ton
TX [b]	Energy Transfer Company	05/24/2012	Jackson County Gas Plant – amine unit vent after thermal oxidizer	73,000 MMscf/yr CO_2 per plant	None specified	48,370 tons per year per plant	>$80 per ton

a- South Dakota Department of Environment and Natural Resources PSD permit 28.0701, September 15, 2011.
b- Statement of Basis Permit Number: PSD-TX-1264-GHG March 2012 issued by USEPA Region 6.

Table 6-2 Cost Effectiveness for CCS System for CO_2 Stripper Vent

COST ELEMENT	Case 1 100% CCS	Case 2 50% CCS; 50% EOR/Sell
Process Parameters		
CO2 Mass, tons/yr	231,261	231,261
Pipeline Distance, miles	20	20
Compressor Power, kW	5,000	5,000
Pump Power, kW	500	500
Capital Costs		0
Compressor Capital Cost, $/kW	$4,000	$4,000
Pump Capital Cost, $/kW	$4,000	$4,000
Compressor Capital Cost, 2005 $	$20,000,000	$20,000,000
Pump Capital Cost, 2005 $	$2,000,000	$2,000,000
Cost multiplier 2005 to 2012	1.25	1.25
Compressor & Pump Cost, 2012 $	**27,500,000**	**27,500,000**
Pipeline Cost, 2007 $	$14,197,471	$14,197,471
Cost multiplier 2011 to 2012	1.00	1.00
Pipeline Cost, 2012 $	**14,197,471**	**14,197,471**
Storage Cost, 2010 $	121,776,199	60,888,099
Cost multiplier 2010 to 2012	1.06	1.06
Storage Cost, 2012 $	**129,082,771**	**64,541,385**
Total Capital Cost, 2012 $	**$170,780,242**	**$106,238,857**
Annual Operating Costs		$0.00
Power Costs, $/yr	$2,775,168	$2,775,168
O&M Costs, $/yr	$6,831,210	$4,249,554
Sale of 50% of CO2 to Denbury, $/yr	NA	-$1,156,304
Annualized Capital Costs, $/yr	$16,120,447	$10,028,196
Total Annual Cost, $/yr	**$25,726,824**	**$15,896,615**
Cost Effectiveness		
Cost effectiveness	$111	$69
CO2 from power, tons/yr	22,957	22,957
Avoided Cost effectiveness	$124	$76
Comparison to Project Cost		
Capital Cost of Project without CCS	$1,100,000,000	$1,100,000,000
Annualized Capital Cost of Project, $/yr	$103,840,000	$103,840,000
CCS cost as % of Project Cost	**25%**	**15%**

Table 6-3 Cost Effectiveness for CCS System for Steam Option 1 - Cogeneration Facility

COST ELEMENT	VALUE
Process Data	
CO_2 before CCS, tons/yr	388,712
GHG before CCS (CO2e), tons/yr	389,094
Environmental Impacts	
Percent CO_2 Reduction, %	90%
CO_2 Captured, tons/yr	349,841
CO_2 Emitted after CCS, tons/yr	38,871
CO_2 Emitted by CCS, tons/yr	57,223
Total CO_2 Emitted with CCS, tons/yr	96,094
CO_2 Reduction due to CCS (avoided), tons/yr	292,619
Water Consumption, million gallons/yr	169
Collateral NO_X Increase, tons/yr	48.5
Collateral CO Increase, tons/yr	7.3
Collateral VOC Increase, tons/yr	1.0
Collateral PM10/PM2.5 Increase, tons/yr	3.2
Collateral SO_2 Increase, tons/yr	1.7
Energy Impacts	
Steam & Power, mmBtu/yr	979,000
Steam, mlb/hr	124
Power, MW	5.720
Economic Impacts	
Carbon Capture	
Escalated Capital Costs, $	$144,600,000
Capital Cost Annualized (9.4% CRF), $/yr	$13,700,000
O&M Costs, $/yr	$37,100,000
Total Annual Cost, $/yr	$50,800,000
Cost Effectiveness, $/ton	$145
Avoided Cost Effectiveness, $/ton	$174
Transport and Sequestration	
Total Annual Cost (ratioed from Case 1 cost in Table 6-2), $/yr	$43,285,083
Cost Effectiveness, $/ton	$124
Total Cost Effectiveness, $/ton	**$297**
Comparison to Project Cost	
Capital Cost of Project without CCS, $	$1,100,000,000
Annualized Capital Cost of Project, $/yr	$103,840,000
CCS cost as % of Project Cost	**91%**

Appendix A

Emissions Calculations

Table A-1 EO/EG Plant CO2 Stripper Vent GHG Emissions

Vent Flow Rate:	53,333	lb/hr average
CO2 Content:	>99%	(assume 100% for GHG permitting)
Operating Schedule:	8760	hr/yr
Annual Emissions:	**233,597**	**tpy**

Note: This calculation applies to both the vent from the catalytic oxidation unit that will convert any trace VOC to CO2, and to the catalytic oxidation unit bypass vent. Because the composition of the vent stream is essentially 100% CO2, the GHG emissions are the same whether emitted prior to or after the catalytic oxidation unit.

Table A-2 Option 1 - Cogen Unit GHG Emissions

EPN: U-2650 | **Turbine: TBD**

Specifications

Parameter		Value	Unit
Fuel Type : Natural Gas			
		1,029	Btu/scf
Annual Average Firing Rate:	Turbine	477.10	mmBtu/hr
	duct burner	147.40	mmBtu/hr
	Factor Basis	**Emission Factor**	
CO2 Emission Factor	Part 98, App C	53.02	kg/mmBtu
CH4 Emission Factor	Part 98, App C	0.001	kg/mmBtu
N2O Emission Factor	Part 98, App C	0.0001	kg/mmBtu
Operating Hours	Turbines	8760	hrs/year
	Duct Burners	8760	hrs/year

Emission Rates

Pollutant	Actual tpy	CO2e Factor	CO2e tpy
Cogen Alone:			
CO2	319,725	1	319,725
CH4	6.0	21	127
N20	0.6	310	187
Total CO2e	NA	NA	320,039
Cogen/Boiler Combined Limit*:			
CO2	388,712	1	388,712
CH4	7.3	21	154
N20	0.7	310	227
Total CO2e	NA	NA	389,094

*The basis for Cogen/Boiler Combined Limit assumes the Cogen Unit operates at full load with duct firing 8760 hrs per year, and the backup boilers are operating as represented on the Auxiliary Boiler calculation sheet. If the cogeneration unit is down for an extended period of time, one of the boilers would become the primary steam source during that period. This condition results in less GHG emissions than the cap basis and is thus also included in and covered by the cap.

Sample Calculations:

GHG emissions calculated from factors in Section 2.3 of Appendix C to 40 CFR Part 75 as follows:

$$\text{Turbine/Duct Burner CO2} = \frac{624.5\ \text{MMBtu}}{\text{hr}} \left| \frac{53.0\ \text{lb}}{\text{MMBTU}} \right| \frac{2.205\ \text{lb}}{\text{kg}} \left| \frac{1\ \text{ton}}{2000\ \text{lb}} \right| \frac{8{,}760\ \text{hr}}{\text{yr}} = 319{,}725\ \text{tpy}$$

$$\text{Turbine/Duct Burner CH4} = \frac{624.5\ \text{MMBtu}}{\text{hr}} \left| \frac{0.001\ \text{kg}}{\text{MMBTU}} \right| \frac{2.205\ \text{lb}}{\text{kg}} \left| \frac{1\ \text{ton}}{2000\ \text{lb}} \right| \frac{8{,}760\ \text{hr}}{\text{yr}} = 6\ \text{tpy}$$

Table A-3 Option 1 - Cogen Facility Auxiliary Boiler GHG Emissions

EPN: (U-2651, U-2652)

Specifications

Parameter	Factor Basis	Value	Unit
Fuel Type : Natural Gas			
		1,029	Btu/scf
Maximum Firing Rate, each		550.00	mmBtu/hr
Standby Firing Rate, each		55.00	mmBtu/hr
	Factor Basis	**Emission Factor**	
CO2 Emission Factor	Part 98, App C	53.02	kg/mmBtu
CH4 Emission Factor	Part 98, App C	0.001	kg/mmBtu
N2O Emission Factor	Part 98, App C	0.0001	kg/mmBtu
Operating Hours	Normal Full load	219	hrs/year
	Standby	8541	hrs/year
	Extended Full Load*	4380	hrs/year

Emission Rates

Pollutant	Actual tpy	CO2e Factor	CO2e tpy
Contribution to Combined Limit:			
CO2	68,987	1	68,987
CH4	1.3	21	27.32
N20	0.13	310	40.34
Total CO2e	NA	NA	69,055
Per Boiler Limits*:			
CO2	140,791	1	140,791
CH4	2.7	21	55.76
N20	0.27	310	82.32
Total CO2e	NA	NA	140,929

*Extended Full Load is for Per Boiler Limit that would apply to one boiler in the event that the Cogen Unit was out of service for an extended period of time.

Sample Calculations:

$$\text{Annual CO2} = \frac{550.0\ \text{mmBtu}}{\text{hr}} \left|\ \frac{53\ \text{kg}}{\text{mmBTU}}\ \right|\ \frac{2.205\ \text{lb}}{\text{kg}}\ \left|\ \frac{1\ \text{ton}}{2000\ \text{lb}}\ \right|\ \frac{219\ \text{hr}}{\text{yr}} = 68{,}987\ \text{tpy}$$

Table A-4 Option 2 - Boiler Emissions

EPN: (U-2651, U-2652, U-2653)

Specifications					Emission Rates		
Parameter		**Value**	**Unit**	**Pollutant**	**Actual tpy**	**CO2e Factor**	**CO2e tpy**
Fuel Type : Natural Gas				Per Boiler			
		1,029	Btu/scf	CO2	281,333	1	281,333
Maximum Firing Rate		550.00	mmBtu/hr	CH4	5	21	111
Standby Firing Rate		55.00	mmBtu/hr	N20	1	310	164
	Factor Basis	**Emission Factor**		Total CO2e	NA	NA	281,609
CO2 Emission Factor	Part 98, App C	53.02	kg/mmBtu				
CH4 Emission Factor	Part 98, App C	0.001	kg/mmBtu	All Boiler Caps			
N2O Emission Factor	Part 98, App C	0.0001	kg/mmBtu	CO2	350,568	1	350,568
				CH4	6.6	21	139
Operating Hours		8760	hrs/year	N20	0.7	310	205
Standby Operation of Backup boilers		97.50%	of year	Total CO2e	NA	NA	350,912
Full Load Operation of Backup boilers		2.50%	of year				

Sample Calculations:

$$\text{Annual CO2} = \frac{550.0\ \text{mmBtu}}{\text{hr}} \times \frac{53\ \text{kg}}{\text{mmBTU}} \times \frac{2.205\ \text{lb}}{\text{kg}} \times \frac{1\ \text{ton}}{2000\ \text{lb}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} = 350{,}568\ \text{tpy}$$

Table A-5 Process Vents to Flare GHG Emissions (Routine)

Process Unit			**P66**	**P67**	**P64**	**P66**	**P61**				
Description			**Guard Bed Vent (C-6667)**	**Glycol Auxillary Cond. Pot (C-6765)**	**Condensate Vent EO Breakthrough (C-6412)**	**Chemical Tank Vents (C-6608)**	**EO Reaction Cycle Gas Purge**	**Analyzer Vent Streams**	**EO Loading Emissions**	**Pilot**	**TOTAL**
Production (Continuous/Intermittent)			**Intermittent**	**Continuous**	**Intermittent**	**Intermittent**	**Intermittent**	**Continuous**	**Intermittent**	**Continuous**	
Exit Temperature (C)			40.00	105.00	105.00	40.00	47.00	40.00	15.74		
Mass Flow Rate (Kg/h)	Minimum		1,030.90	2,100.00	2,500.00	0.00	800.00	0.01	0.01	41.81	
	Maximum		1,134.00	2,310.00	2,500.00	6.00	3,000.00	0.01	0.01	41.48	
Molar Flow Rate (kgmoles/hr)	Minimum		36.75	116.44	137.47	0.00	37.43	0.00	0.00	2.59	
	Maximum		40.43	128.08	137.47	0.24	140.35	0.00	0.00	2.61	
Emission Composition (Mole Fraction)	**Molecular Weight lb/lbmole**	**Carbons per Mole**									
Inert Gases (N2, O2 & Ar)	28.00	0	0		0.007	0.900	0.150	0.500			
CH4	16.04	1	0.0003		0.003		0.559			1	
C2H4	28.05	2	0.9995	0.000001	0.005		0.280	0.500			
C2H6	30.07	2	0.0002		0.00001		0.00200				
C3H8	44.00	3									
Ethylene Oxide	44.05	2			0.001				1.000		
CO2	44.00	1		0.000161	0.001		0.005				
SO2	64.00	0									
Water Vapor	18.00	0		0.9986	0.982		0.004				
Ethyl Chloride	98.96	2									
Promoter	?										
Ethylene Glycol (MEG)	62.07										
Diethylene Glycol (DEG)	106.12										
Triethylene Glycol	150.00										
Tetraethylene Glycol	194.00										
Aldehydes	44.05	2		0.001206	0.000532						
Nitromethane	61.04	1			0.000041						
Hydrogen	2.02	0									
Ethyl Chloride	64.51	2				0.100					
Average MW			28.0507999	18.04	18.19	25.20	21.38	28.03	44.05	16.04	
Mole Fraction Check Sum			1	1	1	1	1	1	1	1	
Speciated Mass Emission Rates (Kg/hr)	**Molecular Weight lb/lbmole**										
Inert Gases (N2, O2 & Ar, Assume N2 MW)	28.00		0.00	0.00	27.38	3.00	373.33	0.00	0.00	0.00	
CH4	16.04		0.19	0.00	6.87	0.00	797.15	0.00	0.00	41.65	
C2H4	28.05		1082.03	0.00	17.49	0.00	698.22	0.00	0.00	0.00	
C2H6	30.07		0.23	0.00	0.05	0.00	5.35	0.00	0.00	0.00	
C3H8	44.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Ethylene Oxide	44.05		0.00	0.00	7.40	0.00	0.00	0.00	0.01	0.00	
CO2	44.00		0.00	1.18	6.36	0.00	19.56	0.00	0.00	0.00	
SO2	64.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Water Vapor	18.00		0.00	3002.87	2430.87	0.00	6.40	0.00	0.00	0.00	
Ethyl Chloride	98.96		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Promoter			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Ethylene Glycol (MEG)	62.07		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Diethylene Glycol (DEG)	106.12		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Triethylene Glycol	150.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Tetraethylene Glycol	194.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Aldehydes (assume acetaldehyde)	44.05		0.00	8.87	3.22	0.00	0.00	0.00	0.00	0.00	
Nitromethane	61.04		0.00	0.00	0.34	0.00	0.00	0.00	0.00	0.00	
Hydrogen	2.02		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Ethyl Chloride	64.51					0.77	0.00	0.00	0.00	0.00	
Stream Flow Rate (kg/hr)			1,082.45	3,012.93	2,500.00	3.77	1,900.00	0.01	0.01	41.65	
Stream Flow Rate (SCFH)			14,878.73	64,411.34	53,004.90	57.65	34,272.42	0.10	0.07	1,001.29	
Stream Flow Rate (SCFM)			247.98	1,073.52	883.42	0.96	571.21	0.00	0.00	16.69	
Continuous Vent Annual Duration =	8760		hours/year								
Intermittent Vent Annual Duration =	100		hours/year								
Control/Destruction Efficiency =			99%	99%	99%	99%	99%	99%	99%		
Total CO2 after combustion (lb/hr):			**3,646.61**	**20.33**	**109.24**	**1.41**	**4,738.19**	**0.01**	**0.02**	**122.72**	
Total CO2 after combustion (tons/year):			**182.33**	**89.04**	**5.46**	**0.07**	**236.91**	**0.05**	**0.00**	**537.52**	**1,051.4**

Table A-6 EO/EG Plant Process Fugitive GHG Emissions

Component	Count in VOC Service	SOCMI Emission Factor (lb/hr-component)	Uncontrolled Emissions (tons/year)	Control Efficiency (28 MID/CNTQ)	Controlled Emissions (tons/year)
Valves - Gas, w/ ethylene[1]	53	0.0258	6.0	97%	0.18
Valves - Gas[2]	550	0.0132	31.8	97%	0.95
Valves - Gas, w/o ethylene[3]	1,161	0.0089	45.3	97%	1.36
Valves - Light Liquid, w/ ethylene[1,4]	0	0.0459	0.0	97%	0.00
Valves - Light Liquid[2,4]	0	0.0089	0.0	97%	0.00
Valves - Light Liquid, w/o ethylene[3,4]	721	0.0035	11.1	97%	0.33
Valves - Heavy Liquid[5,7, 8]	2,531	0.0007	7.8	97%	0.23
PSVs	26	0.2293	26.1	100%	0.00
Pumps - Light Liquid, w/ ethylene[1,4]	0	0.144	0.0	93%	0.00
Pumps - Light Liquid[2,4]	0	0.0439	0.0	93%	0.00
Pumps - Light Liquid, w/o ethylene[3,4]	9	0.0386	1.5	93%	0.11
Pumps - Heavy Liquid[5,7, 8]	55	0.0161	3.9	93%	0.27
Compressors[6]	3	0.5027	6.6	95%	0.33
Sampling Connections[6]	120	0.033	17.3	97%	0.52
Flanges/Connectors - Gas, w/ ethylene[1]	54	0.0053	1.3	97%	0.04
Flanges/Connectors - Gas[2]	390	0.0039	6.7	97%	0.20
Flanges/Connectors - Gas, w/o ethylene[3]	1,021	0.0029	13.0	97%	0.39
Flanges/Connectors - Light Liquid, w/ ethylene[1,4]	0	0.0052	0.0	97%	0.00
Flanges/Connectors - Light Liquid[2,4]	97	0.0005	0.2	97%	0.01
Flanges/Connectors - Light Liquid, w/o ethylene[3,4]	667	0.0005	1.5	97%	0.04
Flanges/Connectors - Heavy Liquid[5, 7, 8]	2,564	0.00007	0.8	97%	0.02
TOTAL	10,022		180.7		4.98

[1]Streams containing 85% or more ethylene. Note: Ethylene oxide is not ethylene.

[2]Streams containing between 11 and 85 ethylene. Note: Ethylene oxide is not ethylene.

[3]Streams containing less than 11% ethylene. Note: Ethylene oxide is not ethylene.

[4]A Light Liquid is one with a vapor pressure of greater than 0.044 psia at 68°F.

[5]A Heavy Liquid is one with a vapor pressure of less than 0.044 psia at 68°F. It is assumed that there are no heavy liquid streams containing ethylene.

[6]Emission factor is not dependent upon ethylene content of stream.

[7]Control efficiency for valves and pumps in heavy liquid service based on AVO inspections according to TCEQ guidance

[8]Vapor pressure of heavy liquids < 0.0147 psia

Speciated Process Fugitive Emissions

Service Type	Total Controlled Emissions (tons/year)	Composition		
		Compound	Wt. Fraction	Controlled Emissions (tons/year)
Gas w/ Ethylene	0.22	Ethylene	1	NA
Gas	1.15	Ethylene	0.3	NA
		Methane	**0.55**	**0.63**
		Ethylene Oxide	0.02	NA
		Non-Hydrocarbon	0.13	NA
Gas w/o Ethylene	1.75	Ethylene	0.055	NA
		Ethylene Oxide	0.945	NA
Compressors	0.33	Ethylene	0.5	NA
		Ethylene Oxide	0.5	NA
Sampling Connections	0.52	Ethylene	0.5	NA
		Ethylene Oxide	0.5	NA
Light Liquids w/ Ethylene	0.00	NA	NA	NA
Light Liquids	0.01	Non-Hydrocarbon	1	NA
Light Liquids w/o Ethylene	0.48	Ethylene Oxide	0.02	NA
		Ethylene	0.0002	NA
		Methane	**0.0001**	**0.00**
		Non-Hydrocarbon	0.9797	NA
Heavy Liquids	0.53	Glycols	1	NA
Total	4.98	**Total Methane**		**0.63**
		METHANE (CO2e: Methane x GWP of 21)		**13.33**

Table A-7 Steam Plant Process Fugitive GHG Emissions

Natural Gas

Component	Count	SOCMI Emission Factor (lb/hr-component)	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tons/year)	Control Efficiency (28 MID/CNTQ)	Controlled Emissions (tons/year)
Valves - Gas, w/o ethylene	963	0.0089	8.57	37.54	97%	1.13
Valves - Light Liquid, w/o ethylen	87	0.0035	0.30	1.33	97%	0.04
Valves - Heavy Liquid[2,3,4]		0.0007	0.00	0.00	97%	0.00
PSVs	15	0.2293	3.44	15.07	97%	0.45
Pumps - Light Liquid, w/o ethylene		0.0386	0.00	0.00	93%	0.00
Pumps - Heavy Liquid[2,3,4]		0.0161	0.00	0.00	93%	0.00
Compressors		0.5027	0.00	0.00	95%	0.00
Sampling Connections	6	0.033	0.20	0.87	97%	0.03
Flanges/Connectors - Gas, w/o ethylene	3,507	0.0029	10.17	44.55	97%	1.34
Flanges/Connectors - Light Liquid, w/o ethylene	258	0.0005	0.13	0.57	97%	0.02
Flanges/Connectors - Heavy Liquid[2,3,4]		0.00007	0.00	0.00	97%	0.00
TOTAL	4,836		22.81	99.92		3.00
Methane Weight %	85.78%				**Methane**	**2.57**

Process Vent Gas

Component	Count	SOCMI Emission Factor (lb/hr-component)	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tons/year)	Control Efficiency (28 MID/CNTQ)	Controlled Emissions (tons/year)
Valves - Gas, w/o ethylene	819	0.0089	7.29	31.93	97%	0.96
Valves - Light Liquid, w/o ethylen		0.0035	0.00	0.00	97%	0.00
Valves - Heavy Liquid[2,3,4]		0.0007	0.00	0.00	97%	0.00
PSVs		0.2293	0.00	0.00	97%	0.00
Pumps - Light Liquid, w/o ethylene		0.0386	0.00	0.00	93%	0.00
Pumps - Heavy Liquid[2,3,4]		0.0161	0.00	0.00	93%	0.00
Compressors		0.5027	0.00	0.00	95%	0.00
Sampling Connections	6	0.033	0.20	0.87	97%	0.03
Flanges/Connectors - Gas, w/o ethylene	2,913	0.0029	8.45	37.00	97%	1.11
Flanges/Connectors - Light Liquid, w/o ethylene		0.0005	0.00	0.00	97%	0.00
Flanges/Connectors - Heavy Liquid[2,3,4]		0.00007	0.00	0.00	97%	0.00
TOTAL	3,738		15.93	69.79		2.09
Methane Weight %	70.10%				**Methane**	**1.47**

[1]A Light Liquid is one with a vapor pressure of greater than 0.044 psia at 68°F.

[2]A Heavy Liquid is one with a vapor pressure of less than 0.044 psia at 68°F.

[3]Control efficiency for valves and pumps in heavy liquid service based on AVO inspections according to TCEQ guidance

[4]Vapor pressure of heavy liquids < 0.0147 psia

Total Process Fugitive Methane Emissions

Speciated Hydrocarbon	Controlled Emissions (tons/year)
METHANE	**4.04**
METHANE (CO2e: Methane x GWP of 21)	**84.82**

Table A-8 Emission and Standby Engines - GHG Emissions

EPN	FIN	Description	Fuel	Firing Rate (mmbtu/hr)	Usage (hrs/yr)	Firing Rate (mmbtu/yr)	Emission Rates (tpy)[1]			
							CO_2	CH_4	N_2O	CO_2e
MP-2840A	MP-2840A	FIREWATER PUMP DIESEL DRIVER	No. 2 Diesel	5.09	52	265	21.6	0.0009	0.0002	21.6
MP-2840B	MP-2840B	FIREWATER PUMP DIESEL DRIVER	No. 2 Diesel	5.09	52	265	21.6	0.0009	0.0002	21.6
EGEN-1	EGEN-1	EMERGENCY GENERATOR	No. 2 Diesel	16.19	52	842	68.6	0.0028	0.0006	68.9

Emission Factors:

Emission factors from Tables C-1 & C-2 of Appendix A to 40 CFR Part 98 Chapter C

Fuel	kg CO2/mmBtu	kg CH4 /mmBtu	kg N2O/mmBtu
No. 2 Distillate	73.96	0.003	0.0006

kg to lb conversion factor: 2.20462

CO2e Equivalents:

CO2	1.0
CH4	21.0
N2O	310.0

EO/EG Plant
INEOS USA LLC
8/9/2013

Table A-9 MSS GHG Emissions Summary

Area	Description	Flow Rate to Flare (lb/yr)	CO2e from Purging Equipment to Flare (ton/yr)	CH4 from Opening Equipment to Atmosphere after Purge to Flare (ton/yr)
1	Cycle Gas Loop. Includes EO Reactor and feed/effluent exchangers, EO Absorber, CO2 absorber, Cycle Gas Compressor, Oxygen Mixer and all other in-line equipment items and piping.	1,560.8	212	0.04
2	EO Recovery. Includes EO Stripper/Reabsorber and associated equipment, Vent Gas Compressor and associated equipment and CO2 Regenerator and associated equipment	1.5	0.14	0.00
3	EO Storage Vessels and associated equipment	0.02	0.04	0.00
4	Ethylene Glycol (EG) Reaction, Concentration and Purificaton area and associated equipment	1.6	0.10	0.00
5	Heavy Glycol Reaction and Purification and associated equipment	1.3E-04	0.00	0.00
6	Purge Glycol System	-	0.00	0.00
7	Glycol Storage	-	0.00	0.00
8	Miscellaneous - OSBL Ethylene Pipeline - ISBL Sulfur Guard Bed and Piping - ISBL EC Storage Drum	63.7	10.01	0.00
9	Assist Natural Gas	3,079.6	4.45	0.00
	Total	**4,707.3**	**227**	**0.04**
			MSS-C	MSS-U
	Global Warming Potential		1	21
	Total CO_2e- tons/year		**227**	**0.91**

Note: For all flows to flare except Assist Natural Gas, CO2e emission rate was calculated assuming 100% conversion of all carbon in stream to CO2 per the following example:

CO2e (tpy) = 1,560.8 lb/yr x 44 lb/mol CO2 x (0.32 mol frac C2H4 x 2 mol CO2/mol C2H4 / 28 lb/mol C2H4 + 0.68 mol frac CH4 x 1 mol CO2/mole CH4 / 16 lb/mol Ch4) / 2000 lb/ton x 1 GWP

= 212 tpy CO2e

For natural gas, CO2, CH4, and N2O emissions were calculated using EPA factors in 40 CFR Part 98, Appendix C in the same manner as shown for calculation of GHG from the boilers (see Table A-4).

Appendix B

RBLC Database Search Results

Table B-1 RBLC Database Search Results for Greenhouse Gas Emissions

RBLCID	FACILITY NAME	COMPANY NAME	STATE	PERMIT DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT		CONTROL METHOD DESCRIPTION	EMISSION LIMIT	
Process Vents											
OK-0135	PRYOR PLANT CHEMICAL	PRYOR PLANT CHEMICAL COMPANY	OK	2/23/2009	CARBON DIOXIDE VENT		36.5	T/H	GOOD OPERATION PRACTICES.	3.65	LB/H
Natural Gas Combustion Sources											
*FL-0330	PORT DOLPHIN ENERGY LLC		FL	12/1/2011	Boilers (4 - 278 mmbtu/hr each)	natural gas	0		tuning, optimization, instrumentation and controls, insulation, and turbulent flow.	117	LB/MMBTU
*FL-0330	PORT DOLPHIN ENERGY LLC		FL	12/1/2011	Power Generator Engines (3)	natural gas	0		use of efficient engine design and use of primarily natural gas	181	G/KW-H
*IA-0105	IOWA FERTILIZER COMPANY		IA	10/26/2012	Primary Reformer	natural gas	1.13	mmcf/hr	good combustion practices	117	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	10/26/2012	Startup Heater	Natural gas	110.12	MMBTU/H	good combustion practices	117	LB/MMBTU
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN	CF INDUSTRIES NITROGEN, LLC	IA	7/12/2013	Startup Heater	natural gas	58.8	MMBTU/hr	good operating practices & use of natural gas	117	LB/MMBTU
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN	CF INDUSTRIES NITROGEN, LLC	IA	7/12/2013	Boilers	natural gas	456	MMBTU/hr	proper operation and use of natural gas	117	LB/MMBTU
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN	CF INDUSTRIES NITROGEN, LLC	IA	7/12/2013	Primary Reformer	natural gas	1062.6	MMBTU/hr	good operating practices & use of natural gas	117	LB/MMBTU
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	8/16/2011	AUXILIARY BOILER (AUX-1)	natural gas	338	MMBTU/H	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	117	LB/MMBTU
*MN-0085	ESSAR STEEL MINNESOTA LLC	ESSAR STEEL MINNESOTA LLC	MN	5/10/2012	INDURATING FURNACE	natural gas	542	MMBTU/H		710000	TON/YR
SC-0113	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC	SC	2/8/2012	PELLETIZER	natural gas	75	MMBTU/H	ENERGY EFFICIENT DESIGN AND OPERATION, WASTE HEAT RECOVERY DESIGN, NATURAL GAS/PROPANE.	0	
SC-0113	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC	SC	2/8/2012	BOILERS	natural gas	5	MMBTU/H	GOOD DESIGN AND COMBUSTION PRACTICES.	0	
*SC-0142	SHOWA DENKO CARBON, INC.		SC	6/8/2012	HOT OIL HEATER	natural gas	5	MMBTU/H	GOOD COMBUSTION PRACTICES, ANNUAL TUNE UP, LOW NOX BURNERS	3093	T/YR (CO2E)
*SC-0142	SHOWA DENKO CARBON, INC.		SC	6/8/2012	CARBOTTOM FURNACES	natural gas	18	MMBTU/H	THERMAL OXIDIZER, LOW NOX BURNERS, GOOD COMBUSTION PRACTICES, ANNUAL TUNE-UP, PROCESS OPTIMIZATION	200009	T/YR (CO2E)
*SC-0142	SHOWA DENKO CARBON, INC.		SC	6/8/2012	PITCH IMPREGNATION/PREHEATER	natural gas	12	MMBTU/H	GOOD COMBUSTION PRACTICES, ANNUAL TUNE UP, LOW NOX BURNERS	7424	T/YR (CO2E)
*TX-0627	LONE STAR NGL MONT BELVIEW GAS PLANT(LONE STAR)	ENERGY TRASFER PARTNERS, LP (ETP)	TX	5/24/2012	Compressor Engine Groups	Natural Gas	4775	HP		1871.7	LB CO2/MMSCF
*TX-0627	LONE STAR NGL MONT BELVIEW GAS PLANT(LONE STAR)	ENERGY TRASFER PARTNERS, LP (ETP)	TX	5/24/2012	Plant Heater System	Natural Gas	48.5	MMBTU/H		1102.5	LB CO2/MMSCF
*IA-0105	IOWA FERTILIZER COMPANY		IA	10/26/2012	Primary Reformer	natural gas	1.13	mmcf/hr	good combustion practices	596905	TONS/YR
*IA-0105	IOWA FERTILIZER COMPANY		IA	10/26/2012	Auxiliary Boiler	natural gas	472.4	MMBTU/hr	good combustion practices	51748	TONS/YR
*IA-0105	IOWA FERTILIZER COMPANY		IA	10/26/2012	Auxiliary Boiler	natural gas	472.4	MMBTU/hr	good combustion practices	117	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	10/26/2012	Startup Heater	Natural gas	110.12	MMBTU/H	good combustion practices	638	TONS/YR
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN	CF INDUSTRIES NITROGEN, LLC	IA	7/12/2013	Startup Heater	natural gas	58.8	MMBTU/hr	good operating practices & use of natural gas	345	TONS/YR

Table B-1 RBLC Database Search Results for Greenhouse Gas Emissions

RBLCID	FACILITY NAME	COMPANY NAME	STATE	PERMIT DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT		CONTROL METHOD DESCRIPTION	EMISSION LIMIT	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN	CF INDUSTRIES NITROGEN, LLC	IA	7/12/2013	Boilers	natural gas	456	MMBTU/hr	proper operation and use of natural gas	234168	TONS/YR
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN	CF INDUSTRIES NITROGEN, LLC	IA	7/12/2013	Primary Reformer	natural gas	1062.6	MMBTU/hr	good operating practices and use of natural gas	545674	TONS/YR
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	11/10/2011	COMBINED CYCLE TURBINE GENERATOR U1-STK	Natural Gas	1746	MMBTU/H	Good Combustion Practices	908957.6	LB/H
*TX-0629	BASF TOTAL PETROCHMICALS LP	BASF TOTAL PETROCHMICALS LP	TX	8/24/2012	Gas Turbine Auxiliary Duct Burners	Natural gas	310.4	MMbtu/H	good operating practices & use of natural gas and fuel gas	117786	T/YR
*TX-0629	BASF TOTAL PETROCHMICALS LP	BASF TOTAL PETROCHMICALS LP	TX	8/24/2012	Steam Package Boilers	Natural Gas and Fuel gas	425.4	MMBTU/H	good operating practices & use of natural gas and fuel gas	420095	T/YR
*TX-0629	BASF TOTAL PETROCHMICALS LP	BASF TOTAL PETROCHMICALS LP	TX	8/24/2012	Ethylene Cracking Furnace No. 10	Natural gas or process fuel gas	498	MMBTU/H	good operating practices & use of natural gas and fuel gas	255735	T/YR
Flares											
AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	8/20/2012	Combustion (Flares)	Fuel Gas	35	MMscf/yr	Good Combustion Practices	0	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN	CF INDUSTRIES NITROGEN, LLC	IA	7/12/2013	Flares	natural gas	0		proper operation and use of natural gas	0	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN	CF INDUSTRIES NITROGEN, LLC	IA	7/12/2013	Flares	natural gas	0		good operating practices and use of natural gas	0	
*IA-0105	IOWA FERTILIZER COMPANY		IA	10/26/2012	Ammonia Flare	natural gas	0.4	MMBTU/H	work practice/good combustion practices	0	
Process Fugitives											
*FL-0330	PORT DOLPHIN ENERGY LLC		FL	12/1/2011	Fugitive GHG emissions		0		a gas and leak detection system will be used.	0	
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	11/10/2011	Fugitive Natural Gas emissions_NG-FUG	Natural Gas	0			327.2	T/YR
Diesel Engines											
AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	8/20/2012	Combustion of Diesel by ICEs	ULSD	1750	kW	Good Combustion Practices and 40 CFR 60 Subpart IIII requirements	0	
TX-0481	AIR PRODUCTS BAYTOWN I I	AIR PRODUCTS LP	TX	11/2/2004	EMERGENCY GENERATOR					2.24	LB/H
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	10/27/2011	Main Propulsion Engines	Diesel	0		Use of good combustion practices	700	G/KW-H
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	10/27/2011	Crane Engines (units 1 and 2)	Diesel	0		Use of certified EPA Tier 1 engines and good combustion practices	722	TONS PER YEAR
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	10/27/2011	Crane Engines (units 3 and 4)	Diesel	0		Use of good combustion practices	687	TONS PER YEAR
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	10/27/2011	Emergency Engine	Diesel	0		Use of good combustion practices	14.6	TONS PER YEAR
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	10/27/2011	Emergency Fire Pump Engine	Diesel	0		Use of good combustion practices	2.4	TONS PER YEAR
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	11/10/2011	EMGEN1-STK - DIESEL FIRED EMERGENCY GENERATOR	DIESEL	93.8		diesel fuel containing no more than 0.5 percent sulfur by weight.	7027.8	LB/H
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	11/10/2011	EMGEN1-STK - DIESEL FIRED EMERGENCY GENERATOR	DIESEL	93.8			15314	LB/H

Table B-1 RBLC Database Search Results for Greenhouse Gas Emissions

RBLCID	FACILITY NAME	COMPANY NAME	STATE	PERMIT DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT		CONTROL METHOD DESCRIPTION	EMISSION LIMIT	
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	11/10/2011	FWP1-STK DIESEL FIRED FIRE WATER PUMP	DIESEL	617	HP	Best Work practice	7027.8	LB/H
*IA-0105	IOWA FERTILIZER COMPANY		IA	10/26/2012	Emergency Generator	diesel fuel	142	GAL/H	good combustion practices	1.55	G/KW-H
*IA-0105	IOWA FERTILIZER COMPANY		IA	10/26/2012	Emergency Generator	diesel fuel	142	GAL/H	good combustion practices	788.5	TONS/YR
*IA-0105	IOWA FERTILIZER COMPANY		IA	10/26/2012	Fire Pump	diesel fuel	14	GAL/H	good combustion practices	91	TONS/YR
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN	CF INDUSTRIES NITROGEN, LLC	IA	7/12/2013	Emergency Generators	diesel fuel	180	gal/hr	good combustion practices	509	TONS/YR